Dynamic Economic Dispatch with Sensitivity Analysis

by

Hani Husni Mohammed Odeh

A Thesis Presented to the

FACULTY OF THE COLLEGE OF GRADUATE STUDIES

KING FAHD UNIVERSITY OF PETROLEUM & MINERALS

DHAHRAN, SAUDI ARABIA

In Partial Fulfillment of the
Requirements for the Degree of

MASTER OF SCIENCE

In

ELECTRICAL ENGINEERING

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This thesis, written by Hani Husni Mohammed Odeh under the direction of the his Thesis Advisor and approved by the Thesis Committee, hs been presented to and accepted by the Dean of the College of Graduate Studies, in partial fulfillment of the requirements for the degree of MASTER OF SCIENCE.

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This Thesis is Dedicated to my family

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TABLE OF CONTENTS

		Page No.
List of Tables		ix
List of Figures		xii
Nomenclature		xiii
Abstract		1
CHAPTER 1	INTRODUCTION	3
1.1	General	3
1.2	Problem Description	4
1.3	Literature Review	7
1.4	Scope of Work	11
1.5	Major Contribution of the thesis	15
CHAPTER 2	MATHEMATICAL FORMULATION	17
2.1	Introduction	17
2.2	Objective Function	18
2.2.1	SED Part	20
2.2.2	Redispatch Part	21

TABLE OF CONTENTS

		Page No.
2.3	Constraints	24
2.3.1	SED Part	24
2.3.1.1	Load Demand	24
2.3.1.2	Operating Limit	25
2.3.1.3	Spinning Reserve	25
2.3.1.4	Security Constraints	29
2.3.2	Redispatch Part	31
2.3.2.1	Power Demand	32
2.3.2.2	Power Rate Limit	32
2.3.2.3	Operating Limits	34
2.3.2.4	Spinning Reserve Reqirements	34
2.3.2.5	Security Constraints	35
CHAPTER 3	SOLUTION TECHNIQUES	36
3.1	Introduction	36
3.2	Parametric Programming	37
3.2.1	Perturbation of the Cost Vector	38
3.2.2	Perturbation of the Right Hand Side	43

TABLE OF CONTENTS

		Page No.
CHAPTER 4	TEST CASES, RESULTS, AND CONCLUSION	48
4.1	Introduction	41
4.2	Test Systems	49
4.2.1	AEP 30 Bus System	49
4.2.2	CIGRE System	49
4.3	Test Results	57
4.3.1	Dynamic Economic Redispatch with Sensitivity Analysis	57
4.3.2	Dynamic Economic Redispatch with Transmission Losses and Spinning Reserve in Sensitivity Analysis	105
4.3.3	Dynamic Economic Redispatch with Transmission Losses, Spinning Reserve and Security Constraints	130
CHAPTER 5	CONCLUSIONS AND RECOMMENDATIONS	134
5.1	Summary	134
5.2	Conclusions	136
5.3	Contribution of the Thesis	137
5.4	Recommendations for Future Work	138

TABLE OF CONTENTS

	Page No.
Appendices	139
References	156

LIST OF TABLES

Table No.		Page No.
1	Unit Cost Data of the AEP System	50
2	Load Demand and Spinning Reserve Requirement of the AEP System	51
3	Unit Cost Data of the CIGRE System	53
4	Load Demand and Spinning Reserve Requirement of the CIGRE System	54
5	Distribution of the Units of CIGRE System	55
6	SED for CIGRE System Using Beale's Method	67
6-1	ΔP for CIGRE System	68
7	DER for AEP System Without Sensitivity Analysis	69
8	DERSA CIGRE System with Sensitivity Analysis "C Variation" Version - 1	71
9	DERSA CIGRE System "C-Variation" Version - 2	73
10	DERSA CIGRE System, Units Outputs "C-Variation" Version - 2	75
11	DERSA AEP System "C-Variation"Version - 1	76
12	DERSA AEP System "C-Variation"Version - 2	81
13	DERSA AEP System, Unit Output "C-Variation" Version - 2	86
14	DERSA CIGRE System, Load Variation, "Increasing Load"	87
15	DERSA CIGRE System, Load Variation, "Decreasing Load"	89

LIST OF TABLES

Table No.		Page No.
16	Sharp Load Curve CIGRE System	92
17	CIGRE System (170 MW) Variation in Load Interval 3	94
18	DERSA AEP System, Load Variation "Increasing Load"	95
19	DERSA AEP System, Load Variation" Decreasing Lod"	99
20	CPU Time	104
21	DER of CIGRE System with Network Losses	107
22	DER of AEP System with Network Loses	110
23	DER of AEP System with Network Losses and Spinning Reserve	112
24	DER of CIGRE System with Network Losses and Spinning Reserve	114
25	DER of CIGRE System with Network Losses, Spinning Reserve In Sensitivity Analysis "C Variation"	117
26	DER of AEP System with Network Losses, Spinning Reserve in Sensitivity Analysis "C Variation"	119
27	DER of CIGRE System with losses, Spinning Reserve in Sensitivity Analysis Load Variation	124

LIST OF TABLES

Table No.		Page No.
28	DER of AEP System with Network losses, Spinning Reserve in Sensitivity Analysis Load Variation	126
29	DER of AEP System with Network losses, Spinning Reserve and Security Constraints	132
30	Initial A and F Tables of Beale's Method	147
31	Network Data of AEP System	153
32	Network Data of CIGRE System	155

LIST OF FIGURES

Figure No.		Page No.
1	Typical Input-Output Curve of a thermal unit	19
2	Linearization of cost function about a point	22
3	Flowchart of PP Technique	46
4	Network of the AEP System	52
5	Network of the CIGRE System	56
6	ΔP - Unit Loading AEP System	70
7	Load - variation of the CIGRE System	91
8	Sharp Load Curve CIGRE System	93
9	Load - variation of the AEP System	103
10	Flowchart of Beale's Method	148
11	Flowchart of LP Technique	152

NOMENCLATURE

a_i	=	Base cost of unit i
A	=	Constraint matrix of the Dynamic Economic Dispatch (DED) problem
$A_{\ell-m,i}$	=	Generation shift of line ℓ-m with respect to generating unit i
b_i	=	Linear cost of unit i
c_i	=	Quadratic cost of unit i
C	=	A diagonal matrix having the quadratic cost of all units for all intervals organized interval wise
D	=	A vector having the linear cost coefficients of all units for an interval organized interval wise
$D_{\ell-m,i}$	=	Generalized generation distribution factor of line ℓ-m with respect to generating unit i
$\bar{f}_{\ell-m}$	=	Maximum unit limit of flow of flow of line j connecting bus ℓ to bus m
$\underline{f}^j_{\ell-m}$	=	Minimum limit of flow of line j connecting bus ℓ to bus m
$f^j_{\ell-m}$	=	Flow of line j connecting bus ℓ to bus m
GC_i	=	Maximum generation change of unit i in time intervals
N	=	NG * NP
NG	=	Number of generating units in the system
NP	=	Number of considered time periods
NL	=	Number of monitored lines

$P_{i,k}$ = Active power output of generator i at period k

P_i^{min} = Lower limit of generator i

P_i^{max} = Upper limit of generator i

$P_d^{(k)}$ = System load demand at interval k

$RD_{i,k}$ = Lower bound of power rate limit

$RU_{i,k}$ = Upper bound of power rate limit

$S_{i,k}$ = The available maximum generation of unit i in interval k

SR_i = The maximum spinning reserve allowed on unit i during each interval

SRES(k) = System spinning reserve requirement at period k

T = Time interval of the load curve

x_ℓ = Reactance of line ℓ

X = Vector having the shifted units oututs grouped interval wise.

خلاصة الرسالة

اسم الطالب : هاني حسني محمد عودة
عنوان الدراسة : تحليل حساسية مسألة ترحيل الطاقة الاقتصادي
التخصص : هندسة كهربائية ـ نظم طاقة
تاريخ الشهادة : يونية ١٩٨٩م

تتناول الرسالة تحليل حساسية مسألة اعادة ترحيل الطاقة الاقتصادي التي تتسبب عن التغير الناتج عن عدم دقة حساب الأحمال الكهربائية ، وكذلك عن التغير الناتج عن معامل التكلفة في دالة تكلفة انتاج الطاقة مع مراعاة أن يكون هذا الترحيل بأرخص تكلفة (اقتصادي) وأن يكون في نطاق حدود شروط أنظمة الشبكة الكهربائية . ان دالة التكلفة التي سوف يعمل على تخفيضها تعتبر حاصل جمع دوال التكلفة للمولدات التي تغذي الشبكة الكهربائية في جميع الأوقات الزمنية المختلفة .

ان الطريقة التي اتبعت في هذه الرسالة كونت كالآتي :

يتم استخدام طريقة البرمجة التربيعية لحل الجزء الأول وهو المسمى الترحيل الاقتصادي الساكن للطاقة (بدون الأخذ في الاعتبار لمعدل انتاج الطاقة للمولدات) وبعد ذلك يتم تحويل دالة التكلفة التربيعية الى دالة خطية باستخدام النتائج التي استخلصت من البرمجة التربيعية . ثم تستخدم طريقة البرمجة الخطية للحصول على أفضل النتائج للتغير الناتج في طاقة المولدات التي تغذي الشبكة . ان ناتج طريقة البرمجة الخطية يدمج مع برنامج آخر يدعى البرنامج العاملي والذي يستطيع بدوره دراسة وتحليل مدى حساسية نتائج البرنامج الخطي للمتغيرات التي ذكرت آنفا . في هذه الحالة يعطي البرنامج الخطي معلومات عن الترحيل الاقتصادي المتحرك للطاقة . ان نتائج البرنامجي الخطي تكون تكون غير مجدية اذا كانت غير خاضعة لأي تغيير في احدى العوامل السابقة (اعتبار العوامل ثابتة) .

ان هذه الرسالة تساهم في اختبار ولأول مرة مدى حساسية طريقة ترحيل الطاقة الحركي . وهذه الطريقة تضم في طياتها استخدام طريقة البرمجة التربيعية ، والبرمجة الخطية مع طريقة البرنامج العاملي لحل المشكلة بدون اللجوء لحل عدد كبير جدا من البرامج الخطية (والتي تستهلك وقتا أكبر في الحساب الآلي) نتيجة لتغير طرأ في احدى العوامل حيث تعطي نتائج الحل في هذه الرسالة النطاق الذي يمكن أن تكون عليه هذه العوامل وبذلك يمكن أن يحدث أي تغيير بدون الحاجة الى حلول جديدة للبرنامج الخطي .

درجة الماجستير في العلوم
جامعة الملك فهد للبترول والمعادن
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THESIS ABSTRACT

FULL NAME OF STUDENT: HANI HUSNI M. ODEH

TITLE OF STUDY DYNAMIC ECONOMIC DISPATCH WITH SENSITIVITY ANALYSIS

MAJOR FIELD POWER SYSTEM

DATE OF DEGREE JUNE, 1989

The thesis considers the sensitivity analysis of the Dynamic Economic Dispatch Problem. This involves the variation of the load demand and the cost coefficients of the objective function. The objective function to be minimized is considered to be the sum of the production cost functions of the thermal units (already committed) in all time intervals.

The Dynamic Economic Dispatch problem is solved using a redispatch technique. The latter is formulated considering the load demand, unit limits, system spinning reserve requirement, security constraints of some of the transmission lines and power rate limits of the units. The redispatch technique linearizes the unit outputs about the base case static economic dispatch (SED). The SED solution is obtained using a Quadratic Programming algorithm in this thesis, although any conventional SED algorithm will be suitable. After that the dispatch problem is linearized about the optimum points obtained from the SED solution, a linear program (LP) is used to

calculate the changes in the units output. The LP solution is combined with a parametric program (PP) in order to be able to carry out sensitivity analysis for the LP solution. In this case the LP solution provides dynamic information. A static optimum solution will become obsolete as soon as parameters of the LP model are changed.

The major contribution of this thesis is the application of sensitivity analysis to the redispatch technique to solve the dynamic economic dispatch problem. The solution technique combines QP, LP and PP codes to solve the sensitivity analysis of the dynamic economic redispatch problem without the need for solving a set of different LP problems.

MASTER OF SCIENCE

KING FAHD UNIVERSITY OF PETROLEUM & MINERALS

Dhahran, Saudi Arabia

Date: June, 1989

CHAPTER 1

INTRODUCTION

1.1 GENERAL

The efficient and optimum economic operation of electric power systems has always occupied an important position in electric power industry. In recent decades it is becoming very important for utilities to run their power systems with minimum cost while satisfying their customers demand all the time and trying to make profit. With limited availability of generating units and the large increase in power demand (especially industrial sector), fuel cost and supply limitation, the committed units should serve the expected load demand with the changes in fuel cost and the uncertainties in the load demand forecast in all the different time intervals in an optimal manner.

The basic problem is to be able to meet the demand with the minimum possible cost, this lead initially to the development of the static economic dispatch (SED) in which the load demand is the only constraint treated. SED is suitable for only one period time interval, but for multi time interval it will be difficult to meet the demand load. This is due to the allocation of the system generation using SED during periods of high loads.

SED will automatically allocate the least expensive units close to their upper limit and allocating the most expensive units at later stages.This gives rise to the problem that in some periods the load demand will not be met because of the generator ramping rate constraint. The proper solution to the problem is to use dynamic economic dispatch.

The problem of the dynamic economic dispatch with sensitivity analysis (DEDSA) (considering the allocation of the generating units in all time intervals) is tackled in this thesis. The load demand is considered to be undeterministic since the data of the load demand is estimated with a margin of error. Also it is considered that the cost coefficient of the objective function is undeterministic which might be due to different reasons i.e. changes in the future fuel prices and supply limitations. It is considered in this thesis that unit commitment has already been done and the sensitivity analysis for the dynamic economic dispatch is done only on the available units on line.

1.2 Problem Description

Generating facilities in power systems generally consists of units with different dynamic behavior. The loading rate characteristics (power rate limit) are different due to the maximum gradient for temperature and pressure in the mechanical construction of thermal units, especially in the boiler. The solution of static economic dispatch (SED) problem becomes less reliable since it does not consider the power rate limit which makes it difficult to meet the load during the periods of high load pickups. The dynamic economic dispatch offers a good solution to the problem but the optimum solution becomes obsolete as soon as there are variations in model parameters.

The dynamic economic dispatch is the proper solution for minimization of the cost function, which is the sum of the production cost functions of all the units, during all periods with consideration to sensitivity. The load demand data should not be considered as a deterministic value since it is subject to error and the cost coefficient of the objective function is subject to variation i.e. changes in the price and quality of crude oil. Instead of solving the DED all over again it is of great advantage to investigate the changes in the optimum LP solution resulting from the variations mentioned earlier.

The problem is solved considering the production cost as a function of the real power output of the units and considering the following constraints.

(1) Operating limits (upper and lower limits) of each unit in each period.

(2) Power rate limit of each unit. This particulr constraint links each unit output over every two consecutive periods.

(3) System spinning reserve requirements in each period.

(4) Real power balance equation, that is, the sum of the units output in each period is equal to the load demand plus the network transmission losses. In this, the load demand is treated as undeterministic value in the LP solution.

(5) Security constraints for some of the major lines. The line flows are expressed approximately in terms of the units outputs via the generalized generation distribution factors which are calculated according to the presentations given in reference [8].

1.3 LITERATURE REVIEW

The static economic dispatch problem was considered by most researchers and different solution methods were proposed to the problem [1].

In most of the papers, the authors proposed different methods for solving the dynamic economic dispatch problem (DED), some depend on SED, others depend on dynamic programming, linear and nonlinear programming techniques. Also they all formulated the DED as a minimization problem with the objective function being the sum of the production cost functions of all already committed units during all the intervals. They mostly considered the constraints of the units upper and lower limits, the power rate limits and the load demand.

Van den Bosch [2] used the gradient projection method to solve the reserve constrained SED over one interval and the DED problem considering the power rate limit of each unit. He formulated the power rate constraints in the objective function by using the penalty functions. He solved the problem using the gradient projection method with conjugate search direction. Since the cost function was quadratic and an initial basic feasible solution was required, it was provided by solving the SED problem and using its solution as an initial input feasible basis to the problem.

Wood [3] solved the reserve constraint SED problem based on traditional SED methods,. The transmission losses was considered using the B-Matrix Loss formula. The DED problem was again solved by Wood considering the system reserve, power rate limits, load demand, transmission losses and units limits as constraints on the problem. He solved the problem as SED problem in a backward sequence and the units limits has to be adjusted in each time interval.

Ross and Kim [4] suggested a technique to solve the DED problem using the dynamic programming successive approximation (DPSA) considering the load demand, power rate limits, operating limits of each unit and a state recursive equation representing each unit. The problem was broken into small subproblems, each corresponding to one unit. Since the dynamic programming requires discretization of the power, this determines both the ability to find optimal solution and execution time and the dimension of the problem increases almost exponentially as more units are included.

Isoda [5] solved the DED problem in a technique similar to the one proposed by Wood, moving backward in time while solving SED problem. If load is not satisfied in the first interval it moved forward in time adjusting the operating limits in each period until the load is met in all periods.

Stadlin [6] investigated the allocation of regulating margin economically. He considered the units upper and lower operating limits, the real power balance equation including transmission losses using the B-Matrix loss formula and the regulating margin constraints. The maximum regulating margin of each unit is considered to be 3% of the unit capacity per minute. The problem was solved using lagrange multipliers. The main disadvantage of his formulation that the requirement of 3% of each unit capacity per minute as a regulating margin imposes an unnecessary additional cost especially when meeting light load.

Waight, Base and Sheble' [7] studied the optimal allocation of power system generation among the on line units while meeting the spinning reserve requirement in addition to the unit power rate limits, real power balance equation and operation limits. They considered only one period taking into account the units, generation and system load in the previous period. They formulated the problem as a linear programming whose structure can be decomposed into small subproblems. The Dantzig-Wolfe decomposition technique was applied to solve the decomposed problem which has the same number of subproblems as the number of generating units.

Bechart and Chen [8], proposed a multi-pass dynamic programming approach. This technique passes through the control interval many times in succession, beginning with a coarse time and a state grid and refining the grid pass by pass gradually converging to the optimal trajectories. This approach has some disadvantages, in particular, the unknown convergence of the algorithm to the real optimum and the exponentially increasing computer memory and calculation time requirements, when the dynamic dispatch problem has to be solved for many units.

Farghal, Tantawy, Abu-Hussain and Hassan [9] proposed a technique for optimal redispatch of power generation for system security control considering the unit power rate limits, spinning reserve, frequency deviation limit and line security limits, load demand, and unit limits. They first expressed the base case generation dispatch with system constraints and cost function of generating units in quadratic form. The objective function is linearized as well as the constraints about it's base points obtained from the quadratic solution. Network sensitivity parameters were calculated from the redispatch technique to provide the participation factors of the generators to reduce the transmission lines overloads during contingencies.

The above research work did not study variation in LP model parameters. The LP models are normally concerned with the expected values of the parameters, therefore a range for those parameters makes the LP solution to look a dynamic one.

Aoki and Satoh [10] solved the economic load dispatch poblem using the parametric quadratic programming method with network security constraints. The constraints used are generator output limits (upper and lower), dc load flow security constraints and power balance equation in which transmission losses are expressed as a quadratic form of the generators outputs. The upper bounding technique and the relaxation method are coupled with the parametric quadratic programming method for the purpose of computational efficiency only.

Khunaizi [11] solved the Dynamic Economic Dispatch using the Redispatch Technique based on LP. The cost function is linearized about the points obtained by the corresponding static dispatch to give the redispatch LP in terms of the changes of the units outputs.

1.4 SCOPE OF WORK

From the literature review the following comments are noticed:

(1) All the techniques proposed in the literature i.e. Van den Bosch [2], Wood [3], Ross & Kim [4], Isoda [5]. Stadlin [6], Waight, Base &

Sheble [7] and Bechart & Chen [8], solved a deterministic optimization problem and so do not consider the aspects of the uncertainties in the load and variation in the cost coefficients of the objective function.

(2) Redispatch technique based on Linear Programming is faster in solving the Dynamic Economic Dispatch problem as shown in Reference [11]. Therefore, a sensitivity analysis based linear programming will be more efficient than the Parametric Quadratic Programming proposed by Aoki and Satoh. [10]

(3) Farghal, Tantawy, Abu-Husain and Hassan used the redispatch technique to calculate the network sensitivity parameters to provide the participation factors of the generators to reduce the transmission lines overloads during contingencies.

(4) Khunaizi [11], solved the Dynamic Economic Dispatch using the Redispatch Technique based on LP assuming a deterministic value for both the load demand and the cost coefficient.

In this thesis the problem of dynamic economic dispatch with sensitivity analysis is considered taking into account the units power limits, power rate limits of the units, the system spinning reserve requirements, security constraints of some of the major lines.

The redispatch technique will be used to solve the problem, where it is linearized about the optimum points obtained from the static economic dispatch using a Quadratic programming technique. After that a linear program is introduced to obtain the optimum changes in the outputs of the units with the power rate limits incorporated. Parameteric programming is introduced to find out how far the linear programming solution changes due to changes or variations in the load demand and cost coefficient without the need for successive running of linear program.

The redispatch problem will be formulated as a single optimization problem. The objective function and the constraints are derived in terms of the real power outputs of the units which are already considered as committed units (on line). The sum of the objective functions of the units during all time intervals is considered to be the objective function under minimization. The following constraints are considered to be active during the minimization process.

(1) Operating Limits

These are the bounds on the units output i.e. upper limit and lower limit.

(2) Power Rate Limit

This constraint has to meet the load changes i.e. it links the output of every unit over two intervals (periods).

(3) Spinning Reserve Requirement

This is defined as the amount of the unused generation which is available on line to ensure the system reliability. That is each can only carry a limited amount of fast reserve to be utilized for an emergency state in few minutes depending on each unit ramping rate.

(4) Load Demand Constraint

The total power generation should meet the system load demand and network transmission losses.

(5) Security Constraints

The active power flow in the network transmissin lines must satisfy their boundry limits. The line flows are expressed approximately in terms of the units output via the generation distribution factors [12].

1.5 MAJOR CONTRIBUTION OF THE THESIS

1. Formulation Of The Redispatch Problem With Sensitivity Analysis

In this thesis the dynamic economic dispatch with sensitivity analysis of the power system during all time intervals is formulated based on the Redispatch Technique. The load demand and the cost coefficient are considered as undeterministic values (subject to variation).

2. Algorithm

Beale's method (Quadratic Programming) is used to solve the SED problem in the redispatch case. Parameteric Linear Programming is used to carry out the sensitivity analysis of the Dynamic Economic Dispatch problem.

CHAPTER 2

MATHEMATICAL FORMULATION

2.1 INTRODUCTION

In optimizing a real-life problem one is usually confronted with a function to be maximized or minimized (in our case minimization) as well as numerous constraints that must be met.

The objective function to be minimized here is the cost function of all generating units over all time intervals taking into account the constraints with sensitivity analysis.

In the following sections the mathematical representations of the objective function and constraints are discussed. The mathematical model for the subject problem is established for the optimization problem.

2.2 OBJECTIVE FUNCTION

The thermal unit is considered in this thesis work, therefore, the fuel cost for this type of unit will be used in the optimization process.

The objective function is taken to be the sum of the cost function of all already committed units over all time intervals. The production cost function $F_i(P_i)$ of a generating unit i is approximated by a quadratic function which is found to be the most widely used in the economic dispatch problem. Figure No.1 represent a typical input-output characteristic of a thermal unit.

The production cost function of unit i shall be considered to be:

$$F_i\,(P_i) = a_i + b_iP_i + C_i\,P_i^2 \qquad \$/h \qquad (2.1)$$

The reactive power has minimum effect on the cost function $F_i(P_i)$ and its effect is neglected in this thesis because it mainly controls the voltage and it is controlled by the field current of the unit. The objective function for the optimization process is obtained by summing the cost function of each unit over all time intervals.

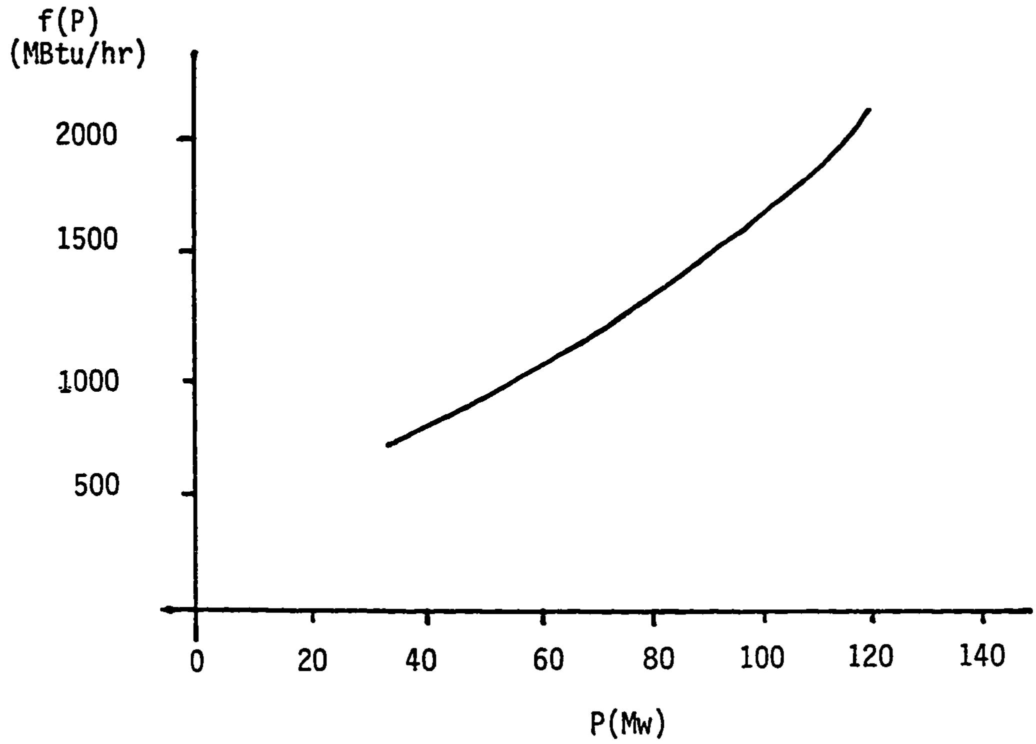


Figure 1. Typical input-output curve of a thermal unit.

The Dynamic Economic Dispatch problem consists of two parts. First, the quadratic part which establishes the base case dispatch and it is called static economic dispatch (SED), Appendix -1. The second part, the Redispatch part, which is an LP that links all time intervals, Appendix -2. The objective functions for both parts are described as follows.

2.2.1 SED Part:

The objective function is the sum of the cost functions of the units over each time interval (SED). Because the SED solves a sequence of uncoupled SED problems, each corresponds to one time interval. The following is the mathematical formulation.

$$F = \sum_{i=1}^{NG} F_{i,k} (P_{i,k}) \tag{2.2}$$

$$= \sum_{i=1}^{NG} (a_i + b_i P_i + C_i P_i^2) \tag{2.3}$$

2.2.2 Redispatch Part

The cost function of each SED problem will be linearized about its optimum solution $P^{o}_{i,k}$ as shown in figure No. 2 to give the following function (by performing the first derivative on the SED objective function).

$$dF_{i,k}/dP_{i,k} = F'_{i,k}\,(P^{o}_{i,k}) = 2C_i P^{o}_{i,k} + b_i \qquad (2.4)$$

Using Taylor series expansion, the cost function $F_{i,k}$ becomes:

$$F_{i,k}(P_{i,k}) = F_{i,k}\,(P^{o}_{i,k}) + F'_{i,k}\,(P^{o}_{i,k}) \cdot \Delta P_{i,k} \qquad (2.5)$$

where

$$\Delta P_{i,k} = P_{i,k} - P^{o}_{i,k} \qquad (2.6)$$

and since $F_{i,k}(P^{o}_{i,k})$ is a constant it will not affect the optimization process. Therefore from linearization a new optimization problem for each interval in terms of the unit output changes $\Delta P_{i,k}$ is formulated and the following is the objective function.

$$F_{i,k} = \sum_{k=1}^{NP} \sum_{i=1}^{NG} (b_i + 2C_i P^{o}_{i,k})\,\Delta P_{i,k}$$

where NP = No. of periods

NG = No. of generators

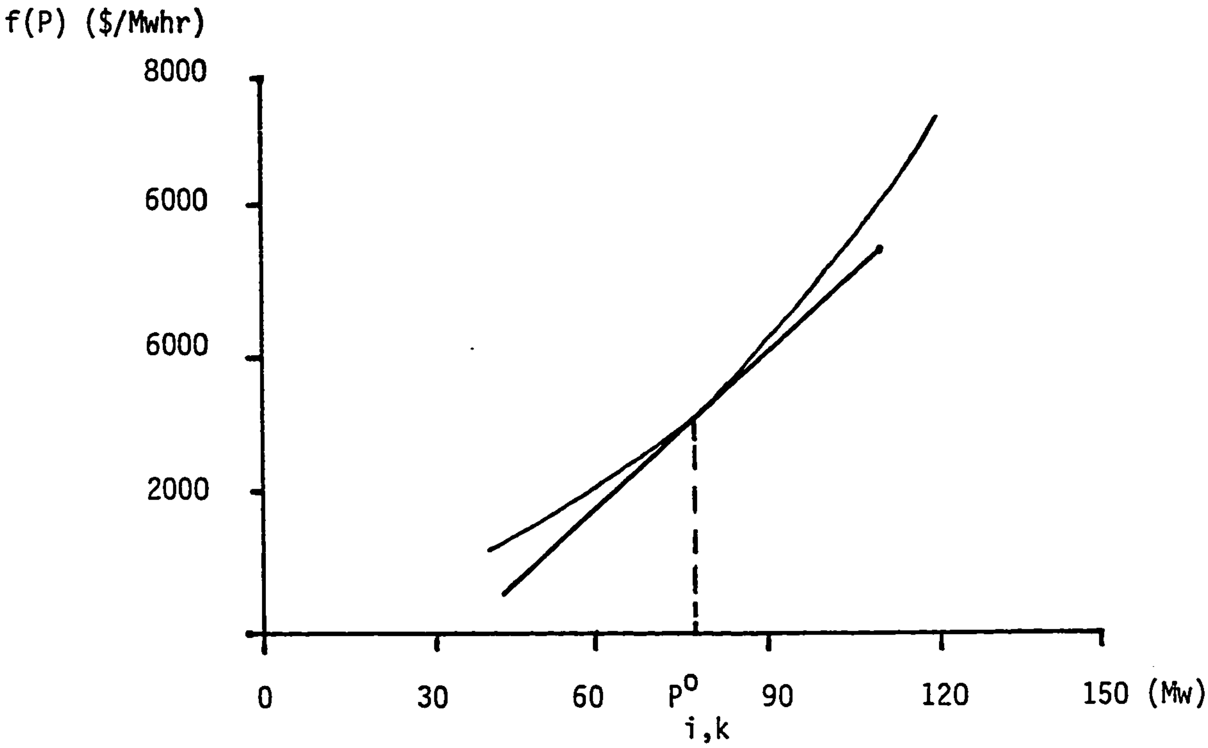


Figure 2: Linearization of cost function about a point.

Considering sensitivity analysis for the cost coefficient the new objective function is formulated as follows:

$$\text{Min} \quad F = \sum_{k=1}^{NP} \sum_{i=1}^{NG} (b_i + 2C_i P^o_{i,k}) \Delta P_{i,k} \tag{2.7}$$

C_i and b_i are the factors which will affect the fuel cost in this case.

∴ Equation (2.7) can be represented as follows:

Min

$$F = \sum_{k=1}^{NP} \sum_{i=1}^{NG} [(b_i + \delta b_i) + (C_i + \delta C_i) P^o_{i,k}] \Delta P_{i,k} \tag{2.8}$$

which can be written as

$$F = \sum_{k=1}^{NP} \sum_{i=1}^{NG} (Cc_i + \delta Cc_i) \Delta P_{i,k} \tag{2.9}$$

and

$$Cc_i + \delta Cc_i = (b_i + \delta b_i) + (c_i + \delta c_i) P^o_{i,k} \tag{2.10}$$

2.3 CONSTRAINTS

The constraints are defined in the following subsections for both parts, the SED part and the Redispatch part.

2.3.1 SED Part

The optimum outputs of the units $P_{i,k}$(i=1 ----NG; k=1 ---NP) should be selected from the feasible region determined by the associated constraints which are explained as follows:

2.3.1.1. Load Demand Constraints

The units outputs of each interval will satisfy the load demand. Therefore, the generation variable $P_{i,k}$ should meet the load demand balance constraint.

$$\therefore \quad \sum_{i=1}^{NG} P_{i,k} = P_d^{(k)} + P_{Loss}^{(k)} \qquad \begin{array}{l} k = 1, \text{----}NP \\ i = 1, \text{----} NG \end{array} \qquad (2.11)$$

where P^k_{loss} is the network transmission losses in interval k. P^k_{loss} is determined by solving the SED problem at the beginning without including P^k_{loss} and with the obtained points of the units outputs a load flow is run to get the initial value of P^k_{loss} , which is fed back to QP to get new SED points.

The process is then iterated between the QP and the load flow until a tolerance criterian of P^k_{loss} is satisfied. The whole process is repeated for each interval and we get finally the SED optimum points $P^o_{i,k}$ (i, 1, ---- NG) for all intervals (k = 1, ---- NP).

2.3.1.2 Operating Limits

Each of the generating units operates between its specified maximum and minimum limits i.e. between P_i^{max} and P_i^{min} as specified by the manufacturer. The unit should not operate below its minimum limit (P_i^{min}). This is due to the fact that the unit's boiler (thermal units) should maintain a constant temperature to prevent slagging, since the unit boiler needs time to heat back, up to the operating temperture. The unit output should be within the following constraints in every period.

$$P_i^{min} \leq P_{i,k} \leq P_i^{max} \qquad (2.12)$$

$$i = 1, \text{---} NG$$
$$k = 1, \text{---} NP$$

2.3.1.3 Spinning Reserve Requirement

Spinning reserve is considered one of the most important factors affecting the power system reliability and security in the normal state. The spinning reserve is the term used to describe the total amount of generation available from all units synchronized (i.e. spinning) on the system minus the present load plus losses being supplied [13]. Spinning reserve must be carried so that the loss of one or more units does not cause drop in system frequency. Quite simply, if one unit is lost, there must be ample reserve on the other units to make up for the loss in a specified time interval.

The amount of spinning reserve required is a management decision depending upon risks and economics, and it differs from one utility to another. Typical rules specify that [13] reserve must be capable of making up the loss of the most heavily loaded unit in a given period of time, or such. Others calculate reserve requirement as a function of the probability of not having sufficient generation to meet the load. Also, if a percentage approach of the daily peak load is used, then any error in the load demand estimate will be reflected in spinning reserve calculations.

Not only must the reserve be sufficient to make up for a generation unit failure but the reserves must be allocated among fast-responding units and slow-responding units. This allows the automatic generation control system to restore frequency and interchange quickly in the event of a generating unit failure.

The available spinning reserve is mainly governed by the power rate limit of each unit, since the unit takes time to respond due to some generation outages. The spinning reserve requirement is defined for each time interval which will be allocated among the committed units. In the definition of the spinning reserve, the power rate limit of each unit, the load demand changes and the upper limit of each unit are taken into consideration.

The spinning required for each time interval SRES(K) is defined as in the following equation:

$$\sum_{i=1}^{NG} GC_{i,k} - \Delta P_d^k \geq SRES(K) \tag{2.13}$$

where $GC_{i,k}$ = maximum generation change of unit i in a time interval K which is given by:

$$GC_{i,k} = \text{Min}\,(P_i^{max} - P_{i,k}\,,\, SR_i) \tag{2.14}$$

where $P_i^{max} - P_{i,k}$ represent the present spare capacity of the unit i.

SR_i = Maximum spinning reserve that the unit can give at that particular interval, which is the maximum generation change the unit can deliver during that particular interval i.e. the power rate limit.

Equation (2.13) can be written as follows [7]:

$$\sum_{i=k}^{NG} \{\min (P_i^{max} - P_{i,k}, SR_i) + \min (P_{i,k+1} - P_{i,k}, 0)\} \geq SRES(K) + \Delta P_d^k \qquad (2.15)$$

$$k=1, \text{---}\ NP$$

The spinning reserve required in each time interval will be assumed according to the following equation.

$$SRES(K) = aP_d^{(k)} + b\ Max.\ (P_{i,k}) \quad [9]$$

$$Max\ (P_{i,k}) = \text{rating of the largest unit}$$

a and b are constraints depending on the system reliability level [9] and are given below:

a = .025 - .05

b = .15 - .23

In equation (2.15) $\quad Min\ (P_{i,k}^{max} - P_{i,k}, SR_i)$

can be replaced by [4, 9].

$$P_{i,k}^{max} - P_{i,k}\ W_{i,k} \leq RU_{i,k}$$

Where $W_{i,k}$ is a non-negative variable representing the amount of spare capacity in the unit. This spinning reserve is unavailable to contribute to the total system spinning reserve requirement such that the spinning reserve on that particular unit is less than or equal to the maximum spinning reserve of the unit.

And Min $(P_{i,k+1} - P_{i,k,0})$ can be replaced by

$$P_{i,k+1} - P_{i,k} - \eta_{i,k} \leq 0$$

where $\eta_{i,k}$ is a nonnegative variable.

And equation (2.15) is transfered into the following:

$$(1) \quad \sum_{i=1}^{NG} (P_{i,k}^{max} - P_{i,k} - W_{i,k}) + (P_{i,k+1} - P_{i,k} - \eta_{i,k}) \geq SRES\,(k) + \Delta P_d^k$$

$$k = 1, \text{---}NP \qquad i = 1, \text{---}NG \qquad (2.16)$$

$$(2) \quad P_{i,k}^{max} - P_{i,k} - W_{i,k} \leq RU_{i,k} \qquad (2.17)$$

$$k = 1, \text{---}NP \qquad i = 1, \text{---}NG$$

$$(3) \quad P_{i,k+1} - P_{i,k} - \eta_{i,k} \leq 0 \qquad (2.18)$$

$$k = 1, \text{---}NP \qquad i = 1, \text{---}NG$$

2.3.1.4 Security Constraints

An overriding factor in the operation of a power system is the desire to maintain system security. System security involves practices designed to keep the system operating when components fail.

System security can be broken down into three major functions that are carried out in an operation control center.

1. System Monitoring
2. Contingency Analysis
3. Corrective Action Analysis

System monitoring provides the operators of the power system with pertinent up-to-date information on the conditions of the power system.This system is called "SCADA" which means "Supervisory Control and Data Acquisition". This data is gathered and placed by the computers in a data base form which operators can display information on large display monitors [13].

Contingency analysis allows the system to be operated defensively. It predicts system troubles including line overload before it happens.

Corrective action analysis allows operating personnel to alter the operation of the power system in the event of an overload or if a contingency analysis program predicts a serious problem should a certain outage occur. A simple type of corrective action involves shifting generation from one generating unit to another. Such shifts can cause power flows to change and thus can alter loading on overloaded lines. Loading limits of these overloaded lines are incorporated into the economic dispatch problem as a security constraint.

In this thesis, it is assumed that the major lines which are mostly to be overloaded are known to us. A corrective action of a defensive type shall be taken by representing the lines load limits in terms of constraints in the economic dispatch. The active power flow in a transmission ($f^{j}_{\ell-m}$) line j connecting bus ℓ and bus m is subject to lie within its upper and lower limits and hence,

$$-f^{j}_{\ell-m} \leq f^{j}_{\ell-m} \leq \bar{f}^{j}_{\ell-m} \qquad (2.19)$$

And it will be expressed in terms of the units outputs using the generalized generation distribution factors (GGDF) [12]. A separate computer program is used to calculate the GGDF.

Equation (2.19) can be written as follows:

$$-f^{j}_{\ell-m} \leq \sum_{i=1}^{NG} D_{\ell-m,i} P_{i} \leq \bar{f}^{j}_{\ell-m} \qquad (2.20)$$

2.3.2 <u>The Redispatch Part</u>

The constraints are linearized similar to the objective function about $P^{o}_{i,k}$. The following constraints are included in the redispatch case.

2.3.2.1 Power Demand

$$\sum_{i=1}^{NG} (P_{i,k} + \Delta P_{i,k}) = P_d^{(k)} + P_{loss}^{k} \qquad (2.21)$$

After arrangement it gives

$$\sum_{i=1}^{NG} \Delta P_{i,k} = P_d^{(k)} + P_{losses}^{k} - \sum_{i=1}^{NG} P_{i,k}^{o} = \delta P_d^{k} \qquad (2.22)$$

Where δP_d^k represents the variation of the load demand characteristic over a specified intervals.

2.3.2.2 Power Rate Limits

This constraint links each unit output over two consecutive periods. This constraint is very important during load pickup together over the whole intervals. The power rate limit most of the time is specified by the unit manufacturer and it differs from one unit to another and it is in the range of 1 - 3%/ minute of the thermal unit rating [13]. The power rate limit is a function of time and it is given by the following inequality:

$$RD_{i,k} \leq P_{i,k+1} - P_{i,k} \leq RU_{i,k} \qquad (2.23)$$

$$i = 1, \text{ --- } NG$$
$$k = 1, \text{ --- } NP$$

Only one side of the inequality is active during each interval for each unit.

$$P_{i,k+1} - P_{i,k} \leq RU_{i,k} \qquad (2.24)$$

or

$$P_{i,k+1} - P_{i,k} \geq RD_{i,k} \qquad (2.25)$$

Inequality (2.24) is the most active and under linearization it becomes:

$$-\Delta P_{i,k} + \Delta P_{i,k+1} \leq RU_i + P^o_{i,k} - P^o_{i,k+1} \qquad (2.26)$$

$$i = 1, \text{ --- } NG$$
$$k = 1, \text{ --- } NP-1$$

Inequality (2.24) will be used in the case of studying a decreasing load demand.

2.3.2.3 Operating Limits

$$P^{o}_{i,k} - P^{min}_{i,k} \leq \Delta P_{i,k} \leq P^{max}_{i,k} - P^{o}_{i,k} \qquad (2.27)$$

$i = 1, \text{---} NG$

$k = 1, \text{---} NP$

2.3.2.4 Spinning Reserve Requirement

1) $$-\Delta P_{i,k} - \Delta W_{i,k} \leq RU_{i,k} + P^{o}_{i,k} + W^{o}_{i,k} - P^{max}_{i,k} \qquad (2.28)$$

$i = 1, \text{---} NG$

$k = 1, \text{---} NP$

2) $$\Delta P_{i,k+1} - \Delta P_{i,k} - \Delta \eta_{i,k} \leq P^{o}_{i,k} + \eta^{o}_{i,k} - P^{o}_{i,k+1} \qquad (2.29)$$

$i = 1, \text{---} NG$

$k = 1, \text{---} NP-1$

3) $$\sum_{i=1}^{NG} (-2\Delta P_{i,k} + \Delta P_{i,k+1} - \Delta W_{i,k} - \eta_{i,k}) \geq SRES(k) + \Delta P^{k}_{d} +$$

$$\sum_{i=1}^{NG} 2P^{o}_{i,k} + W^{o}_{i,k} + \eta^{o}_{i,k} - P^{o}_{i,k+1} - P^{max}_{i} \qquad (2.30)$$

$i = 1, \text{---} NG$

$k = 1, \text{---} NP-1$

2.3.2.5 Security Constraint

$$\sum_{i=1}^{NG} D_{\ell-m,i}\,\Delta P_{i,k} \le f^{j}_{\ell-m} - \sum_{i=1}^{NG} D_{\ell-m,i}\,P^{o}_{i} \qquad (2.31)$$

$i = 1,$ --- NG
$k = 1,$ --- NP
$j = 1,$ --- NL

CHAPTER 3

SOLUTION TECHNIQUES

3.1 Introduction

In this chapter the solution techniques will be presented to solve the dynamic economic redispatch with sensitivity analysis. The basic concepts, algorithmic steps are considered and the theoretical details can be found in the indicated references.

The deterministic Dynamic Economic Dispatch problem is solved using the approach in Ref.[11]. Parametric Programming is used to obtain the range of variation in the Linear programming solution for the load and for the cost coefficient while keeping the feasibility and optimality conditions not violated.

3.2 Parametric Programming:

When an LP problem is formulated for solution by a numerical process, i.e. simplex method, the values of the coefficients of b and c have to be exactly specified. This condition that the coefficients can only take one value often misrepresents the situation for which the LP is a model. Most LP models are concerned with the level of activities in the future, yet often exact quantity and types of fuel that will be available is not known, or all the fuel that has been ordered may not arrive on time. So it is usually the case that the amount of fuel that will be available is known to be within a range of values. The estimate of the load forecast may be subjected to error, since the expected load may be anywhere within a range of values. The values of such elements of b or c that are customarily used to specify the LP are the "expected" or the most "probable" values. It is desirable to find how the solution is affected by variation in the values of the elements of b or c by solving a series of LPs.

Parametric Programming can be used to evaluate the effect of changes in the values of elements of b or c. Parametric programming investigates the changes in the optimum LP solution as the value of a parameter, an element of b or c, varies. This may involve a series of basis changes as the value of the parameter is increased or decreased. Parametric Programming is introduced to find out how the perturbation of the cost vector or load data will affect the optimum LP solution.

3.2.1 Perturbation of the Cost Vector

Consider the following LP problem.

$$\text{Minimize} \quad Z = CX \tag{3.1}$$

$$\text{Subject to} \quad AX = b \tag{3.2}$$

$$X \geq 0 \tag{3.3}$$

Assume that B is an optimal basis. Suppose that the cost vector C is perturbed along the cost direction C', that is, C is replaced by

$$C + \lambda C' \tag{3.4}$$

where $\lambda \geq 0$

$$\text{Let} \qquad X = \begin{bmatrix} X_B \\ \\ X_N \end{bmatrix} \tag{3.5}$$

where X_B = the basic variable vector

X_N = the non-basic variable vector

We are interested in finding the optimal points and the corresponding objective values as a functin of $\lambda \geq 0$.

Decomposing A into [B, N], same as X, where B is the basis matrix and N is the nonbasis matrix, and C' into (C'_B, C'_N), we get [14]

$$Z - (C_B + \lambda C'_B)\, X_B - (C_N + \lambda C'_N)\, X_N = 0 \tag{3.6}$$

$$BX_B + NX_N = b \tag{3.7}$$

Updating the LP tableau and denoting $C_B^{'}Y_j$ by $Z_j^{'}$, gives [14]

$$Z + \sum_{j \varepsilon R} [\, (Z_j - C_j) + \lambda\, (Z_j^{'} - C_j^{'}\,)]\, X_j = C_B\bar{b} + \lambda\, C_B^{'}\bar{b} \tag{3.8}$$

where R is the set of current indices associated with the nonbasic variables.

$$X_B + \sum_{j \varepsilon R} Y_j X_j = \bar{b} \tag{3.9}$$

where

$$\bar{b} = B^{-1} b$$

$$Y_j = B^{-1} a_j$$

The current tableau has $\lambda = 0$ and gives an optimal basic feasible solution of the original problem without perturbation. It is desired to find out how far we can move in the direction C' while still maintaining optimality of the current points.

Let $S = \{ j : (Z'_j - C'_j) \geq 0 \}$ (3.10)

If $S = \phi$, then the current solution is optimal for all values of $\lambda \geq 0$, ϕ is the empty set. Otherwise, calculate λ as follows: [14]

$$\hat{\lambda} = \underset{j \varepsilon S}{\text{Min}} \left\{ \frac{-(Z_j - C_j)}{Z'_j - C'_j} \right\} = \frac{-(Z_k - C_k)}{Z'_k - C'_k} \tag{3.11}$$

Let $\lambda_1 = \hat{\lambda}$. For $\lambda \varepsilon [0. \lambda_1]$ the current solution is optimal and the optimal objective value is given by [14]

$$C_B \bar{b} + \lambda C'_B \bar{b} = C_B B^{-1} b + \lambda C'_B B^{-1} b \tag{3.12}$$

After the tableau is updated, the process is repeated by recalculating S and $\hat{\lambda}$ and letting $\lambda_2 = \hat{\lambda}$. For $\lambda \varepsilon [\lambda_1, \lambda_2]$, the new current solution is optimal and its objective value is given by [14].

$$C_B\bar{b} + \lambda C_B'\bar{b} = C_B B^{-1} b + \lambda C_B' B^{-1} b \tag{3.13}$$

Where B is the current basis. The process is repeated until S becomes empty.

The analysis of C variation can be summarized as follows:

$$AX = b \tag{3.14}$$

$$BX_B + NX_N = b \tag{3.15}$$

$$X_B + B^{-1}NX_N = B^{-1}b \tag{3.16}$$

$$X_B = B^{-1}b - B^{-1}N\,X_N \tag{3.17}$$

$$= B^{-1}b - \sum_{j\varepsilon R} B^{-1}\,a_j X_j \tag{3.18}$$

where R is the current set of the indices of the nonbasic variables.

Let Z denote the objective function

$$Z = CX \quad (3.19)$$

$$= C_B X_B + C_N X_N \quad (3.20)$$

$$= C_B (B^{-1}b - \sum_{j\varepsilon R} B^{-1}a_j X_j) + \sum_{j\varepsilon R} C_j X_j \quad (3.21)$$

$$= (Z_o - \sum_{j\varepsilon R} Z_j X_j) + \sum_{j\varepsilon R} C_j X_j \quad (3.22)$$

$$= Z_o - \sum_{j\varepsilon R} (Z_j - C_j) X_j \quad (3.23)$$

where $(Z_j - C_j)$ is called the Z-coefficient, and the following are noticed.

1) If all X_B and X_N equal to zero, then all variables are non basic variables so C_B will not be affected by any change.

2) If all variables are basic variables, then the Z-coefficient = 0.

3) For nonbasic variables the Z-coefficient must be > 0 in order for the nonbasic variables to enter into the solution, in this case they will cause further decrease in the objective function in the case of minimization process.

4) If the Z-coefficient < 0, then the nonbasic variables will cause an increase in the objective function and in this case they will not modify the solution in our cse (Minimization). So they will not enter into the basic variables.

3.2.2 Perturbation of the Right-Hand-Side

Suppose that the right-hand side vector b of equation (3.2) is replaced by

$$b + \lambda b' \text{ , where } \lambda \geq 0 \tag{3.24}$$

This means that the right hand side is perturbed along the vector b'. Since the right-hand side of the primal problem is the objective of the dual problem, perturbing the right-hand side can be analyzed as perturbing the objective function of the dual problem. Suppose that we have an optimal basis B of the original problem, that is, with $\lambda = 0$. The corresponding tableau is given by [14]

$$Z + (C_B B^{-1} N - C_N) X_N = C_B B^{-1} b \tag{3.25}$$

$$X_B + B^{-1}N\,X_N = B^{-1}\,b \tag{3.26}$$

where $C_B B^{-1}\,N - C_N \leq 0$. If b is replaced by $b + \lambda b'$, then the vector $C_B B^{-1}N - C_N$ will not be affected; that is, dual feasibility will not be affected. The only change is that $B^{-1}b$ and will be replaced by $B^{-1}(b + \lambda b')$, and accordingly the objective becomes

$$C_B B^{-1}\,(b + \lambda b') \tag{3.27}$$

As long as $B^{-1}\,(b + \lambda b')$ is nonnegative, the current basis remains optimal. The value of λ at which another basis becomes optimal, can therefore, be determined as follows:

$$\text{Let} \qquad S \;= \{\, j,\ b'_j < 0 \,\} \text{ where } b' = B^{-1}b' \tag{3.28}$$

If $S = \phi$, then the current basis is optimal for all values of $\lambda \geq 0$. Otherwise, [14]

$$\hat{\lambda} = \min_{j\varepsilon s} \frac{\bar{b}_r}{-\bar{b}'_j} = \frac{\bar{b}_r}{-\bar{b}_r} \tag{3.29}$$

Let $\lambda_1 = \hat{\lambda}$. For $\lambda \varepsilon\ [\ 0,\ \lambda 1\ ]$ the current basis is optimal, where $X_B = B^{-1}(b + \lambda b')$ and the optimal objective is

$$C_B B^{-1} (b + \lambda b') \tag{3.30}$$

At λ_1, the right hand side is replaced by $B^{-1}(b + \lambda_1 b')$, X_B is removed from the basis and an appropriate variable enters the basis. After the tableau is updated the process is repeated in order to find the range of $[\lambda_1, \lambda_2]$ over which the new basis is optimal, where $\lambda_2 = \lambda$. The process is terminated when either S is empty, in which case the current basis is optimal for all values of λ greater than or equal to the last value of λ or else when all the entries in the row whose right-hand side dropped to zero, are non-negative. In the latter case no feasible solution exist for all values of λ greater than the current value. [14]

The Dynamic Economic Redispatch with Sensitivity Analysis can be summarized by the steps shown in the flowchart of Figure (3).

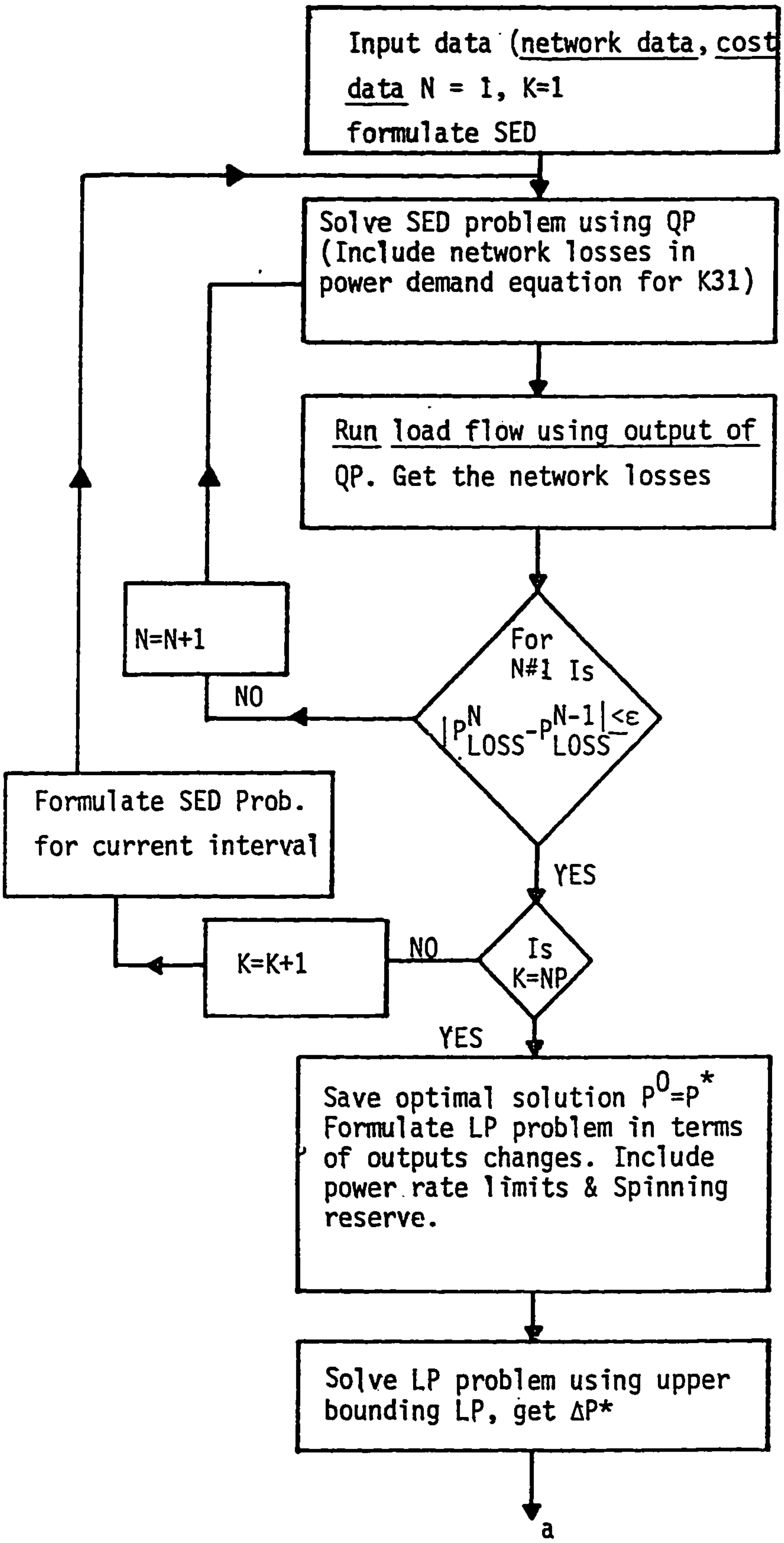
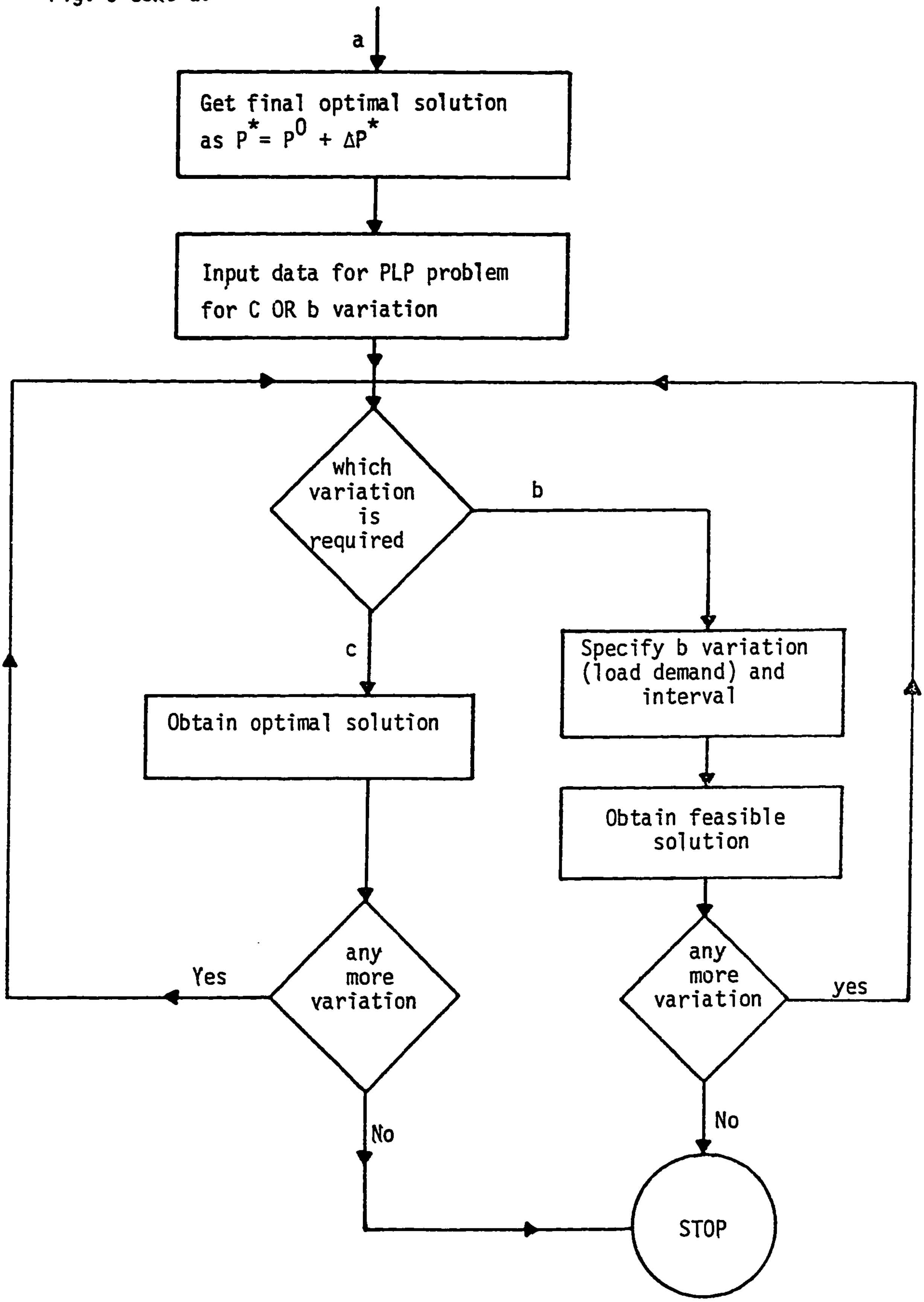


Fig. (3) Flowchart of PP technique.

Fig. 3 Cont'd.


a
Get final optimal solution as $P^{*} = P^{0} + \Delta P^{*}$
Input data for PLP problem for C OR b variation
which variation is required
b
c
Obtain optimal solution
Specify b variation (load demand) and interval
Obtain feasible solution
any more variation
Yes
No
any more variation
yes
No
STOP

CHAPTER 4

TEST CASES, RESULTS, AND CONCLUSION

4.1 Introduction

In this chapter the technique of the dynamic economic redispatch with sensitivity analysis is applied to two systems; the AEP 30 bus system with 6 units and 16 time intervals and the CIGRE system 10 buses, 14 units and 6 time intervals. The two systems are chosen to show the effect of the technique on both of them for comparison purposes.

Both systems data i.e. unit cost data, netowrk data and diagram of each system are described and shown in the following sections. The test results are presented for different combination of constraints as shown in following sections.

The following tables show the unit cost data. The network data of the two systems are given in appendix 3. Each interval has a time span of 10 minutes.

4.2 Test Systems

4.2.1 AEP 30 Bus System

This system has 6 units and 41 lines. Table 1 shows the units cost data and Table 2 shows the load demand and spinning reserve requirement. Figure No. 4 shows the network diagram.

4.2.2 CIGRE System

This system has 14 units, 10 buses, and 13 lines. Units cost data and system load demand are given respectively in Tables 3 and 4. Table 5 indicates the distribution of units. Figure 5 shows the network diagram.

TABLE 1. Units Cost Data for the AEP System.

Unit	Cost coefficient limit			Real unit limit		Reactive Unit Limit		Rate limit	
#	A	B	C	MIN MW	MAX MW	MIN MVAR	MAX MVAR	RU_i	RD_i
1	1122	15.84	0.003124	150	600	-60	450	35	-40
2	620	15.7	0.00388	100	400	-40	300	20	-20
3	156	15.94	0.00964	50	200	-20	150	10	-20
4	950	13.414	0.002641	150	600	-60	450	40	-50
5	560.5	14.174	0.003496	100	450	-40	320	25	-30
6	560.5	14.174	0.003496	100	450	-40	320	25	-30

TABLE 2. Load Demand & Spinning Reserve Requirement of AEP System.

Interval #	Real power	SRES	Reactive power
1	1000	47.5	445.3
2	1030	48.25	458.8
3	1060	49.0	472.6
4	1110	50.25	494.2
5	1170	51.75	520.9
6	1240	53.5	552.3
7	1330	55.75	592.2
8	1420	58.0	632.4
9	1505	60.125	670.6
10	1590	62.25	708.4
11	1670	64.25	743.0
12	1750	66.25	779.7
13	1820	68.0	810.4
14	1885	69.625	839.4
15	1945	71.125	866.5
16	2000	72.5	891.1

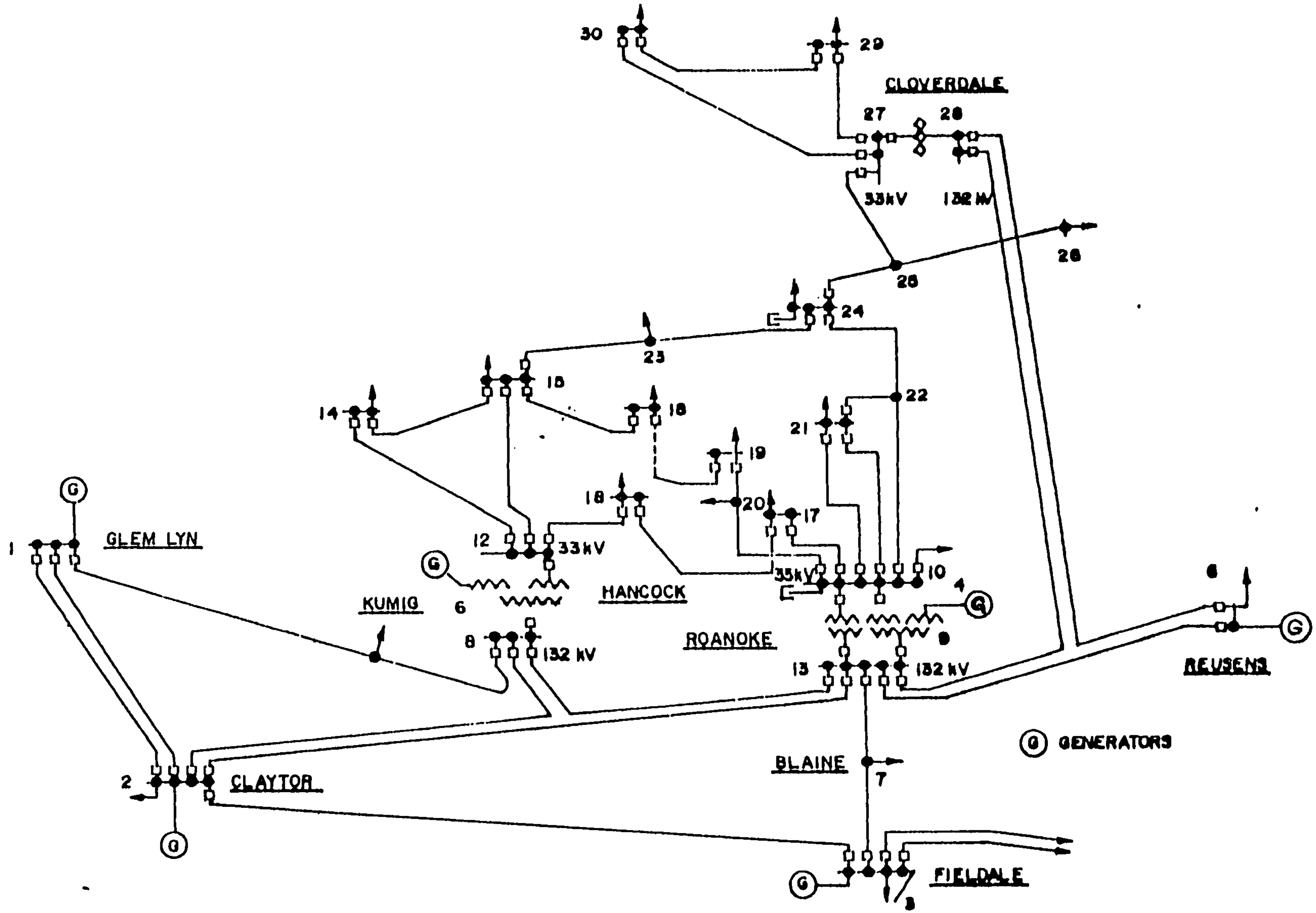


Fig. (4) The Network of the AEP System

TABLE 3. Units Cost Data of CIGRE System.

Unit #	Cost coefficient A	B	limit C	Real unit limit MAX MW	MIN MW	Reactive Unit Limit MIN MVAR	MAX MVAR	Rate limit RU_i	RD_i
1	155.48	0.489	0.00393	240	80	120	-24	35	-35
2	26.025	1.513	0.00602	80	30	40	- 8	22	-22
3	79.339	0.678	0.00773	120	40	75	-15	28	-28
4	168.56	0.394	0.00393	240	80	120	-24	35	-35
5	39.85	1.367	0.0623	120	40	75	-15	28	-28
6	63.755	0.675	0.01033	120	40	75	-15	28	-28
7	59.406	0.803	0.00966	120	40	75	-15	28	-28
8	147.91	0.395	0.00443	240	80	120	-24	35	-35
9	144.51	0.538	0.00407	240	80	120	-24	35	-35
10	123.73	0.773	0.0034	240	80	120	-24	35	-35
11	122.41	0.768	0.0035	240	80	120	-24	35	-35
12	137.77	0.623	0.00384	240	80	120	-24	35	-35
13	66.876	0.636	0.010008	120	40	75	-15	28	-28
14	63.36	0.696	0.00978	120	40	75	-15	28	-28

TABLE 4. Load Demand of CIGRE Sytem.

Time interval	Real load (MW)	Spinning Reserve	Reactive load MVAR
1	980	60.5	506.0
2	1045	62.1	571.0
3	1310	68.75	688.0
4	1470	72.78	785.3
5	1665	77.6	908.0
6	2020	79.5	1028.5

TABLE 5. Distribution of Units of CIGRE System.

Bus	Corresponding units
1	1
2	2 + 3
3	4 + 5
4	6 + 7
5	8 + 9
6	10
7	11 + 12 + 13 + 14

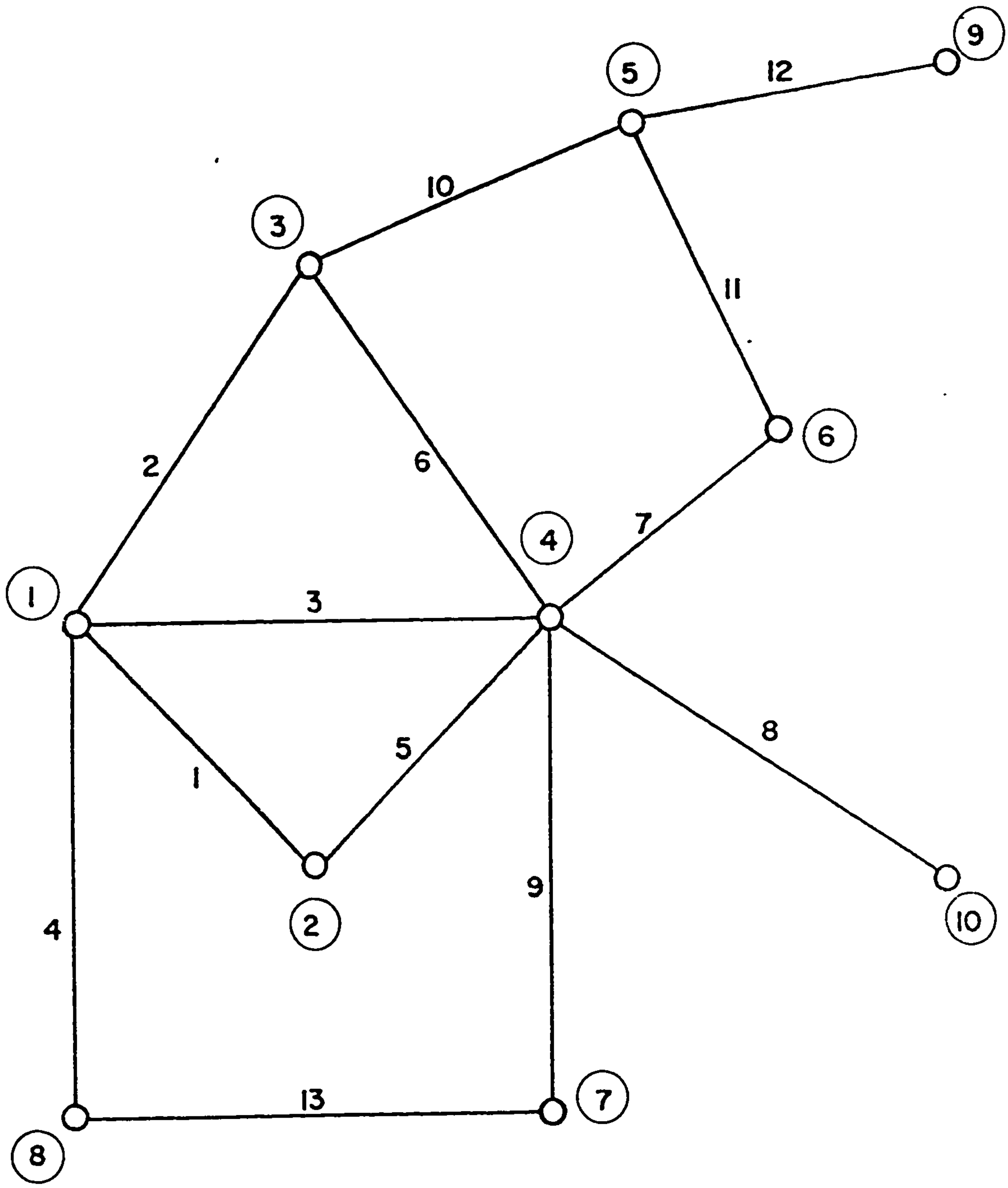


Figure No. 5: The network of the CIGRE System

4.3 TEST RESULTS

The AEP 30 bus system and CIGRE system are tested for different cases and they will be shown in the coming sections, and execution time is also obtained. The cases were tested in KFUPM Mainframe (IBM 3038 and AMDHAL 5850 Computers). The following sections show the different test cases that were carried out.

4.3.1 Dynamic Economic Redispatch with Sensitivity Analysis (DERSA)

First, the AEP 30 bus system and CIGRE system were tested for the initial case i.e. without any parametric variation. The initial case is defined to be dynamic econmic redispatch . In this (initial) case the spinning reserve transmission losses and security constraints are not included. As explained in Chapter 3, the problem starts by using the Quadratic program to solve the Static Economic Dispatch (SED), then it is combined with the Linear Program to form the Dynamic Economic Redispatch (DER) as shown in the following mathematical representation summary.

$$\text{Min} \quad F_k = \sum_{i=1}^{NG} F_{i,k} = \sum_{i=1}^{NG} a_i + b_i P_i + C_i P_i^2 \tag{4.1}$$

where $F_{i,k}$ is the unit cost function in period k subject to the following constraints

1 - Power demand

$$\sum_{i=1}^{NG} P_{i,k} = P_d^{(k)} \qquad (4.2)$$

$i = 1, --- NG$

2 - Units Operating Limits

$$P_{i,k}^{Min} \leq P_{i,k} \leq P_{i,k}^{Max} \qquad (4.3)$$

$i = 1, --- NG$

and the linear part which contribute the redispatch part is considered to be

$$\text{Min } F = \sum_{k=1}^{NG} \sum_{i=1}^{NG} (b_i + 2C_i P_{i,k}^{o}) \Delta P_{i,k} \qquad (4.4)$$

$i = 1, --- NG$
$k = 1, --- NP$

subject to:

1 - Power Demand

$$\sum_{i=1}^{NG} \Delta P_{i,k} = 0 \qquad (4.5)$$

2 - Power Rate Limit

$$-\Delta P_{i,k} + \Delta P_{i,k+1} \leq RU_i + P^o_{i,k} - P^o_{i,k+1} \tag{4.6}$$

3 - Operating Limits

$$P^o_{i,k} - P^{min}_{i,k} \leq \Delta^P_{i,k} \leq P^{max}_{i,k} - P^o_{i,k} \tag{4.7}$$

This case is named as dynamic economic redispatch and when sensitivity analysis is added as shown below it is called dynamic economic redispatch with sensitivity analysis (DERSA). The linear part is changed to the following.

Min

$$F = \sum_{k=1}^{NP} \sum_{i=1}^{NG} (Cc_i + \delta Cc_i) \Delta P_{i,k} \tag{4.8}$$

subject to

1 - Power Demand

$$\sum_{i=1}^{NG} \Delta P_{i,k} = \delta P^k_d \tag{4.9}$$

Load variation is studied for increasing and decreasing conditions of the load demand as shown in the tables.

Power rate limit, equation (4.6), and operating limits, equation (4.7), are also included in the constraints.

The results of the DER and DERSA are presented in Tables 6-20, and the following are noticed:

I. "Cost -Coefficient " - Variation CIGRE and AEP Systems

1) Table 8 and 11 show the sensitivity analysis of the cost coefficients (C vector) for CIGRE and AEP Systems respectively. Table 8 and 11 give the ranges that the cost coefficients can have without affecting the optimality conditions (keeping the initial basic variables unchanged for the whole range of C). The range of the C- coefficients is very valuable data since it saves a lot of computer time in running the LP program and data preparation for any change in the cost coefficients values. The negative sign in the lower range of the C value is not valid for our case since C can have only positive values in the power system cost function. In this case all negative sign values should be replaced by zeros.

2) If C has a value outside its range for a basic variable, then this will cause the variable to become a nonbasic variable. If we

run a case for CIGRE system again, then some nonbasic variables become basic variables and the basic variables now become nonbasic variables. An example for that are C_{66} and $_{67}$have the following ranges (units 10 and 11 interval 5), table 8.

$$0 \quad < C_{66} < 3.025$$

$$0 \quad < C_{67} < 2.511$$

Any change outside these ranges will cause the corresponding value of ΔP to become nonbasic variable and some nonbasic variables to become basic variables. As an example a case study was done for C_{66} and C_{67} to have values of 3.0 and 3.76 respectively and the results of that ΔP corresponding to C_{66} and C_{67} become nonbasic variables and new variables become basic variables as shown in table 9, units 8 and 9 interval 5. The effect of changing the values of the cost coefficients of units 10 and 11 in interval 5 outside their ranges, cause little changes in SED results. This causes little variation in the units loading and generation cost, but the cheapest units remained to be the most loaded ones as shown in table (10). Similarly for AEP system and an example of this are the C – coefficient of units 5 and 6, intervals 6 and 7, (C_{35} and C_{36}) and unit 4, interval 9 (C_{52}) table 11 have the following ranges.

$$1.64 < C_{35} < 18.04$$
$$1.64 < C_{36} < 18.04$$
$$15.7 < C_{52} < 17.3$$

and any change outside these ranges will cause the corresponding value of ΔP to become nonbasic vaiable and some nonbasic variables to become basic variables. As an example a case study was done for C_{35} , C_{36} and C_{52} to have a value of 19.0 and 17.9 respectively (outside its range), the results show that the values of ΔP corresponding to C_{35}, C_{36} and C_{52} become nonbasic variables table 12, and new variables unit-2 interval 10, 11, and unit-1 interval 12 to become basic variables. The effect of changing the values of the cost coefficients of units 5 and 6 intervals 6 & 7 and unit - 4 interval 9 outside their ranges cause little changes in the SED results. This causes little variation in the units loading and generation cost, but the cheapest cost units in table (7) remained to be the most loaded ones as shown in table (13).

3) The program spares the time for data preparation every time there is a change in the value of C and the computer time too.

III. "Load" - Variation CIGRE And AEP Systems

1. Table 14 and 18 show the study of 10% increase in the load demand (in LP, $\Delta P = 0$) for the load demand for CIGRE and AEP Systems. For CIGRE System intervals 1, 2, 3, 4, and 5 show an actual feasible increase of more than 10% but interval No. 6 shows only 4% is the actual feasible increase. This information is very useful in power system operational planning in order to be able to view the range of the load that we can have while meeting this range with the available committed units. For AEP System intervals 1, 2, and 3 show an actual feasible increase of more than 10% but intervals 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, and 16 show an actual feasible increase of less than 10% of the load.

2) Tables 15 and 19 show the maximum feasible decrease in the load demand for CIGRE and AEP Systems without affecting the feasibility of the solution. This makes the LP program a dynamic one by the use of the Parametric Programming to avoid successive running of the LP program for any change that occurs.

3) Figures No. (7) and (9) show the curves of the actual feasible increase, 100% load demand and the actual feasible decrease in the load demand for both CIGRE and AEP Systems respectively. The area between the maximum feasible increase curve and the maximum feasible decrease curve represents the amount of the uncertainties that we can have in the load data without affecting the feasibility of the solution.

4) Table 16 and figure (8) shows the behaviour of the LP solution for sharp increase and decrease in the load demand for CIGRE system. This proves that the solution provided by the program follows the load demand curve.

5) Table 17 shows that the PLP program examines the whole variation in the units output in all periods for any variation in the load demand in any period. For example in period 3 of CIGRE System the possible variation in the load demand is 170 MW, but the program does not test the units outputs in period 3 only, it checks the effect of this on other periods. A comparison of this can be made between table 13 and 15. The units outputs in periods 1, 2, 3, 4, and 6 in both tables are the same and in period 5 there are small differences in the outputs of units 5 and 12.

V. Table (20) shows the execution time (CPU time) for SED (quadratic program by Beale's), LP and PLP.

Table (6) : SED for CIGRE System using Beales Method

Interval	Units 1	2	3	4	5	6	7	8	9	10	11	12	13	14	Load	Cost
1	100.2	30.0	43.8	122.3	40.0	40.0	40.0	108.0	100.4	86.0	84.0	95.3	40.0	40.0	980	2411.6
2	118.7	30.0	48.0	130.9	40.0	40.0	40.0	115.6	108.6	95.0	93.4	104.0	40.0	40.0	1045	2501.8
3	149.0	30.0	63.5	161.1	40.0	48.0	44.4	143.0	138.0	130.5	127.5	135.0	51.0	49.0	1310	2911.2
4	166.3	30.0	72.3	178.4	40.0	54.3	51.4	158.0	155.0	151.0	147.0	153.0	58.0	56.0	1470	3187.8
5	186.0	36.4	82.3	198.1	47.0	62.0	59.4	176.0	174.0	173.0	169.0	173.0	66.0	64.0	1665	3554.0
6	220.0	58.4	99.5	231.8	68.0	75.0	73.0	205.5	206.0	212.0	207.0	207.4	79.0	78.0	2020	4273.3

CPU Time = 0.29 Seconds

Table (6-1)

Δ P CIGRE SYSTEM

For the DRR ΔP is nonzero for only interval - 5.

ΔP - Interval - 5

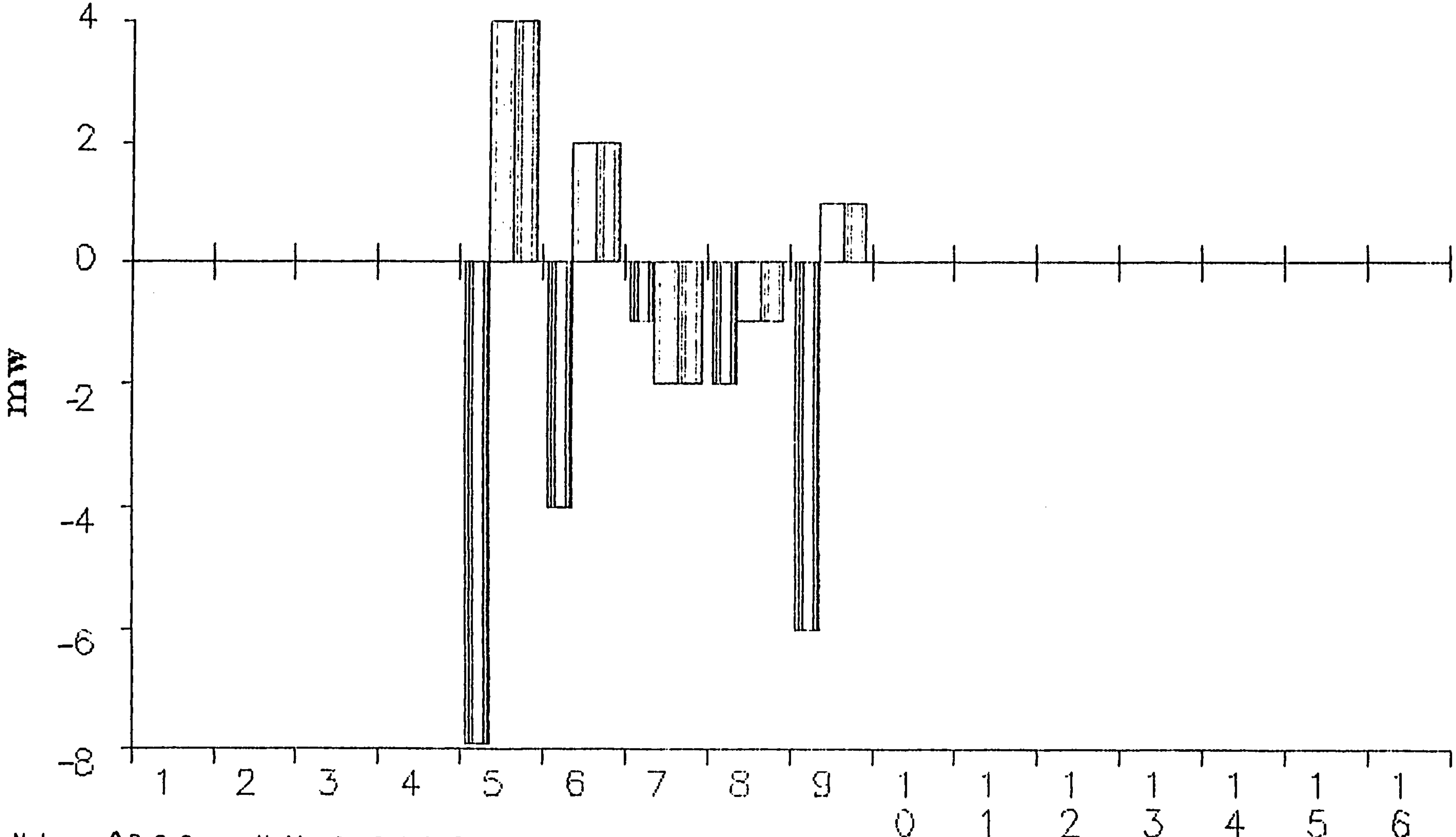
Units	1	2	3	4	5	6	7	8	9	10	11	12	13	14
P	0	0.0116	0	0	-6.7	0	0	0	0	3.9	2.86	-.114	0	0

Total CPU Time for all intervals = 0.23 Seconds

Table (7): DER For AEP System Without Sensitivity Analysis

Unit	Interval	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Output	Load	1000	1030	1060	1110	1170	1240	1330	1420	1505	1590	1670	1750	1820	1885	1945	2000
	Cost	19003.7	19498.0	19962.1	20738.2	21676.5	22779.9	24241.7	25666.6	20753.5	28455.2	29786.9	31132.8	32319.2	33427.9	34457.4	35406.1
	P^0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	168.5	186.5	203.1	218.5	232.5
1	$P^0 + \Delta P$	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	168.5	186.5	203.1	218.5	232.5
2		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	111.0	134.6	153.7	168.2	181.6	193.9	205.2
		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	103.6	111.0	134.6	153.7	168.2	181.6	193.9	205.2
3		50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	55.2	60.6	65.6	70.2
		50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	55.2	60.6	65.6	70.2
4		365.4	377.4	389.3	409.2	433.1	461.0	498.8	532.6	566.5	596.0	600.0	600.0	600.0	600.0	600.0	600.0
		365.4	377.4	389.3	409.2	425.2	457.3	496.4	531.0	560.6	596.0	600.0	600.0	600.0	600.0	600.0	600.0
5		167.3	176.3	185.4	200.4	218.5	239.5	266.6	293.7	319.3	341.5	367.7	388.8	404.9	419.8	433.5	446.0
		167.3	176.3	185.4	200.0	222.4	241.4	264.4	292.7	320.5	341.5	367.7	388.8	404.9	419.8	433.5	446.0
6		167.3	176.3	185.4	200.4	218.5	239.5	266.6	293.7	319.3	341.5	367.7	388.8	404.9	419.8	433.5	446.0
		167.3	176.3	185.4	200.4	222.4	241.4	264.4	292.7	320.5	341.5	367.7	388.8	404.9	419.8	433.5	446.0

CPU Time = 0.523 Seconds



Note: ΔP=0.0 per Units 1, 2 & 3 for all intervals

Figure No. (6)
ΔP- Unit Loading AEP System

Table (8): (DERSA) CIGRE System

with Sensitivity Analysis

"C Variation" Version - 1

Units	Interval 1 ΔP	Value C	Range C	2 ΔP	Value C	Range C	3 ΔP	Value C	Range C
1	0	1.984	0<C<∞	0	2.05	-1.98<C<∞	0	2.29	1.74<C<∞
2	0	2.235	0<C<∞	0	2.35	-1.98<C<∞	0	2.24	1.74<C<∞
3	0	1.963	0<C<∞	0	2.04	-1.98<C<∞	0	2.28	1.74<C<∞
4	0	1.984	0<C<∞	0	2.05	-1.98<C<∞	0	2.29	1.74<C<∞
5	0	2.364	0<C<∞	0	2.36	-1.98<C<∞	0	2.36	1.74<C<∞
6	0	2.328	0<C<∞	0	2.33	-1.98<C<∞	0	2.49	1.74<C<∞
7	0	2.349	0<C<∞	0	2.34	-1.98<C<∞	0	2.43	1.74<C<∞
8	0	2.064	0<C<∞	0	2.13	-1.98<C<∞	0	2.37	1.74<C<∞
9	0	2.01	0<C<∞	0	2.073	-1.98<C<∞	0	2.31	1.74<C<∞
10	0	1.90	0<C<∞	0	1.97	-1.97<C<∞	0	2.20	-2.2<C<∞
11	0	1.915	0<C<∞	0	1.98	-1.98<C<∞	0	2.22	-1.74<C<∞
12	0	1.97	0<C<∞	0	2.036	-1.98<C<∞	0	2.27	-1.74<C<∞
13	0	2.243	0<C<∞	0	2.24	-1.98<C<∞	0	2.46	-1.74<C<∞
14	0	2.261	0<C<∞	0	2.26	-1.98<C<∞	0	2.44	-1.74<C<∞

Cont'd. on p. 72

Cont'd. Table (8): (DERSA) CIGRE System

Version - 1

Units	Interval 4 ΔP	Value C	Range C	5 ΔP	Value C	Range C	6 ΔP	Value C	Range C
1	0	2.43	0<C<∞	0	2.58	-2.57<C<∞	0	2.84	2.3 <C<∞
2	0	2.24	0<C<∞	.0116	2.31	-2.31<C<∞	0	2.58	-2.58<C<∞
3	0	2.41	0<C<∞	0	2.57	2.56<C<∞	0	2.83	2.3 <C<∞
4	0	2.43	0<C<∞	0	2.58	-2.56<C<∞	0	2.84	2.3 <C<∞
5	0	2.36	0<C<∞	-6.7	2.45	- 2.45<C<∞	0	2.71	2.2 <C<∞
6	0	2.62	0<C<∞	0	2.78	- 2.57<C<∞	0	3.04	2.3 <C<∞
7	0	2.57	0<C<∞	0	2.72	- 2.57<C<∞	0	2.99	2.3 <C<∞
8	0	2.51	0<C<∞	0	2.66	- 2.57<C<∞	0	2.92	2.3 <C<∞
9	0	2.45	0<C<∞	0	2.60	- 2.57<C<∞	0	2.87	2.3 <C<∞
10	0	2.34	0<C<∞	3.9	2.50	2.49<C<3.025*	0	2.76	-2.76 <C<∞
11	0	2.35	0<C<∞	2.86	2.51	-2.51<C<2.511*	0	2.78	-2.78 <C<∞
12	0	2.40	0<C<∞	-.114	2.56	-2.57<C<∞	0	2.82	2.3 <C<∞
13	0	2.60	0<C<∞	0	2.75	-2.57<C<∞	0	3.02	2.3 <C<∞
14	0	2.58	0<C<∞	0	2.73	-2.57<C<∞	0	3.0	2.3 <C<∞

CPU

Time 0 = 0.717 Seconds

Table (9): (DERSA) CIGRE System

"C Variation" Version 2

Units	Interval 1 ΔP	Value C	Range C	2 ΔP	Value C	Range C	3 ΔP	Value C	Range C
1	0	2.01	0<C<∞	-1.69	2.08	-2.02<C<∞	0	2.34	1.76<C<∞
2	0	2.23	0<C<∞	0	2.23	-2.49<C<∞	0	2.24	1.84<C<2.27
3	0	1.94	0<C<∞	-6.3	2.01	-2.49<C<∞	0	2.27	2.24<C<∞
4	0	1.95	0<C<∞	-1.69	2.023	-2.02<C<∞	0	2.28	1.76<C<∞
5	0	2.36	0<C<∞	0	2.36	-2.49<C<∞	0	2.36	2.24<C<∞
6	0	2.33	0<C<∞	0	2.33	-2.49<C<∞	0	2.48	2.24<C<∞
7	0	2.35	0<C<∞	0	2.36	-2.49<C<∞	0	2.43	2.24<C<∞
8	0	2.025	0<C<∞	-5.45	2.1	-2.10<C<∞	0	2.36	1.84<C<∞
9	0	1.97	0<C<∞	-2.84	2.046	-2.05<C<∞	0	2.31	1.78<C<∞
10	0	1.71	0<C<∞	18.87	1.78	-1.78<C<2.18	-.159	2.04	-2.04<C<∞
11	0	3.19	0<C<∞	0	3.19	-2.49<C<∞	0	3.19	2.23<C<∞
12	0	1.94	0<C<∞	-.91	2.01	-2.01<C<∞	0	2.27	1.75<C<∞
13	0	2.5	0<C<∞	0	2.5	-2.49<C<∞	0	2.47	2.24<C<∞
14	0	2.26	0<C<∞	0	2.26	-2.49<C<∞	0	2.44	2.24<C<∞

Cont'd. on p.74

Cont'd. Table (9): (DERSA) CIGRE System "C Variation" Version 2

Units	Interval 4 ΔP	4 Value C	4 Range C	5 ΔP	5 Value C	5 Range C	6 ΔP	6 Value C	6 Range C
1	0	2.49	0<C<∞	5.69	2.66	-2.32<C<2.61*	0	2.98	-2.9 <C<∞
2	0	2.24	0<C<∞	4.56	2.33	-2.33<C<2.35*	0	2.65	-2.64<C<∞
3	0	2.42	0<C<∞	0	2.59	-2.32<C<∞	0	2.91	2.02<C<∞
4	0	2.43	0<C<∞	4.22	2.6	2.59<C<3.38*	0	2.91	-2.9 <C<∞
5	0	2.36	0<C<∞	0	2.47	-2.32<C<∞	0	2.79	2.02 <C<∞
6	0	2.63	0<C<∞	0	2.79	-2.32<C<∞	0	3.12	2.02 <C<∞
7	0	2.57	0<C<∞	0	2.74	-2.32<C<∞	0	3.07	2.02 <C<∞
8	0	2.51	0<C<∞	1.1	2.68	-2.32<C<2.69*	0	3.0	-2.99 <C<∞
9	0	2.45	0<C<∞	4.29	2.62	-2.32<C<2.64*	0	2.94	-2.93 <C<∞
10	0	2.19	0<C<∞	-26.5	2.32	-2.32<C<∞	0	2.32	2.02 <C<∞
11	0	3.19	0<C<∞	0	3.19	-2.32<C<∞	0	3.50	2.02 <C<∞
12	0	2.42	0<C<∞	6.64	2.59	-2.32<C<∞	0	2.91	-2.89 <C<∞
13	0	2.62	0<C<∞	0	2.79	-2.32<C<∞	0	3.12	2.02 <C<∞
14	0	2.58	0<C<∞	0	2.76	-2.32<C<∞	0	3.08	2.02 <C<∞

CPU

Time = 0.717 Seconds

Table (10): DERSA - *CIGRE* System units outputs for

"C Variation, Version - 2"

Interval	Units 1	2	3	4	5	6	7	8	9	10	11	12	13	14	Load	Cost
1 P^0	105.8	30.0	41.9	117.9	40.0	40.0	40.0	104.5	96.2	113.1	80.0	90.9	40.0	40.0	980	2424.5
$P^0 + \Delta P$	105.8	30.0	41.9	117.9	40.0	40.0	40.0	104.5	96.2	113.1	80.0	90.9	40.0	40.0		
2	115.1	30.0	46.3	127.2	40.0	40.0	40.0	112.7	105.1	128.1	80.0	103.4	40.0	40.0	1045	2514.1
	113.4	30.0	40.0	125.5	40.0	40.0	40.0	107.3	102.3	147.0	80.0	99.5	40.0	40.0		
3	148.4	30.0	63.2	160.5	40.0	47.5	44.1	142.3	137.3	182.2	80.0	134.5	50.9	49.1	1310	2918.3
	148.4	30.0	63.2	160.5	40.0	47.5	44.1	142.3	137.3	182.0	80.0	134.5	50.9	49.1		
4	167.1	30.0	72.7	179.1	40.0	54.6	51.7	158.8	155.3	212.4	80.0	153.5	58.3	56.5	1470	3194.8
	167.1	30.0	72.7	179.1	40.0	54.6	51.7	158.8	155.3	212.4	80.0	153.5	58.3	56.5		
5	188.7	38.1	83.7	200.8	48.6	62.8	60.0	178.0	176.2	240.0	80.0	175.7	66.8	65.2	1665	3566.1
	194.4	42.7	83.7	205.0	48.6	62.8	60.0	179.1	180.5	213.5	80.0	182.3	66.8	65.2		
6	229.4	64.7	104.4	240.0	74.2	78.3	77.1	214.1	215.5	240.0	100.8	217.3	82.7	81.6	2020	4319.6
	229.4	64.7	104.4	240.0	74.2	78.3	77.1	214.1	215.5	240.0	100.8	217.3	82.7	81.6		

CPU Time = is part of CPU time in table (9)

Table (11) (DERSA) AEP System "C" Variation

Version - 1

	Interval 1			2			3			4		
Unit	ΔP	Value C	Range C	ΔP	Value C	Range C	ΔP	Value C	Range C	ΔP	Value C	Range C
1	0	17.71	$0<C<\infty$	0	17.71	$0<C<\infty$	0	17.71	$0<C<\infty$	0	17.71	$0<C<\infty$
2	0	17.25	$0<C<\infty$	0	17.25	$0<C<\infty$	0	17.25	$0<C<\infty$	0	17.25	$0<C<\infty$
3	0	17.90	$0<C<\infty$	0	17.87	$0<C<\infty$	0	17.87	$0<C<\infty$	0	17.87	$0<C<\infty$
4	0	16.14	$0<C<\infty$	0	16.20	$0<C<\infty$	0	16.30	$0<C<\infty$	0	16.37	$0<C<\infty$
5	0	16.04	$0<C<\infty$	0	16.10	$0<C<\infty$	0	16.17	$0<C<\infty$	0	16.30	$0<C<\infty$
6	0	16.04	$0<C<\infty$	0	16.10	$0<C<\infty$	0	16.17	$0<C<\infty$	0	16.30	$0<C<\infty$

Cont'd. p. 77

Continuation of Table (11) (DERSA) AEP System "C" Variation

Version - 1

	Interval 5			6			7		
Unit	ΔP	Value C	Range C	ΔP	Value C	Range C	ΔP	Value C	Range C
1	0	17.71	0<C<∞	0	17.71	-16.6<C<∞	0	17.71	-16.83<C<∞
2	0	17.25	0<C<∞	0	17.25	-16.6<C<∞	0	17.25	-16.83<C<∞
3	0	17.87	0<C<∞	0	17.87	-16.6<C<∞	0	17.87	-16.83<C<∞
4	0	16.50	0<C<∞	-7.88	16.64	-16.6<C<∞	-3.72	16.83	-16.83<C<∞
5	0	16.40	1.5<C<∞	3.94	16.54	1.64<C<18.04*	1.86	16.73	1.83<C<18.2*
6	0	16.40	1.5<C<∞	3.94	16.54	1.64<C<18.04*	1.86	16.73	1.83<C<18.2*

Cont'd. p. 78

Continuation of Table (11) (DERSA) AEP System "C" Variation

Version - I

	Interval 8			9			10		
Unit	Value	Range		Value	Range		Value	Range	
	ΔP	C	C	ΔP	C	C	ΔP	C	C
1	0	17.71	$17.0<C<\infty$	0	17.1	$17.1<C<\infty$	0	17.71	$-17.4<C<\infty$
2	0	17.25	$17.0<C<\infty$	0	17.25	$17.2<C<\infty$	3.6	17.34	$-17.3<C<17.34$
3	0	17.87	$17.0<C<\infty$	0	17.87	$17.2<C<\infty$	0	17.87	$-17.4<C<\infty$
4	0.43	17.02	$15.5<C<17.2$*	1.58	17.20	$15.7<C<17.3$	-5.94	17.40	$-17.4<C<\infty$
5	-.22	16.92	$16.9<C<\infty$	-0.79	17.10	$-17.1<C<\infty$	1.18	17.23	$17.3<C<17.8$
6	-.22	16.92	$16.9<C<\infty$	-0.79	17.10	$-17.1<C<\infty$	1.18	17.23	$17.3<C<17.8$

Cont'd. p.79

Continuation of Table (11) (DERSA) AEP System "C" Variation

Version -1.

Interval	11			12			13		
Unit	Value		Range		Value	Range		Value	Range
	ΔP	C	C	ΔP	C	C	ΔP	C	C
1	0	17.71	17.1<C<∞	0	17.83	0<C<∞	0	17.90	0<C<∞
2	0	17.52	-17.5<C<∞	0	17.67	0<C<∞	0	17.80	0<C<∞
3	0	17.87	17.2<C<∞	0	17.87	0<C<∞	0	17.97	0<C<∞
4	0	17.40	17.2<C<∞	0	17.4	0<C<∞	0	17.40	0<C<∞
5	0	17.44	-17.4<C<∞	0	17.6	0<C<∞	0	17.70	0<C<∞
6	0	17.44	-17.4<C<∞	0	17.6	0<C<∞	0	17.70	0<C<∞

Cont'd. p. 80

Continuation of Table (11) (DERSA) AEP System "C" Variation

Version - 1

	Interval 14			15			16		
Unit	Value		Range		Value	Range		Value	Range
	ΔP	C	C	ΔP	C	C	ΔP	C	C
1	0	18.05	0<C<∞	0	18.14	0<C<∞	0	18.23	0<C<∞
2	0	17.90	0<C<∞	0	17.98	0<C<∞	0	18.10	0<C<∞
3	0	18.10	0<C<∞	0	18.17	0<C<∞	0	18.25	0<C<∞
4	0	17.40	0<C<∞	0	17.40	0<C<∞	0	17.40	0<C<∞
5	0	17.81	0<C<∞	0	17.90	0<C<∞	0	17.99	0<C<∞
6	0	17.81	0<C<∞	0	17.90	0<C<∞	0	17.99	0<C<∞

CPU Time = 0.69 Seconds

Table (12) (DERSA) AEP System "C" Variation

Version - 2

Unit	Interval 1			2			3			4		
	ΔP	Value C	Range C	ΔP	Value C	Range C	ΔP	Value C	Range C	ΔP	Value C	Range C
1	0	17.71	$0<C<\infty$	0	17.71	$0<C<\infty$	0	17.71	$0<C<\infty$	0	17.71	$0<C<\infty$
2	0	17.25	$0<C<\infty$	0	17.3	$0<C<\infty$	0	17.25	$0<C<\infty$	0	17.30	$0<C<\infty$
3	0	17.90	$0<C<\infty$	0	17.87	$0<C<\infty$	0	17.87	$0<C<\infty$	0	17.87	$0<C<\infty$
4	0	16.10	$0<C<\infty$	0	16.15	$0<C<\infty$	0	16.26	$0<C<\infty$	0	16.40	$0<C<\infty$
5	0	22.40	$0<C<\infty$	0	22.52	$0<C<\infty$	0	22.60	$0<C<\infty$	0	22.76	$0<C<\infty$
6	0	22.40	$0<C<\infty$	0	22.52	$0<C<\infty$	0	22.60	$0<C<\infty$	0	22.76	$0<C<\infty$

Cont'd. on p. 82

Continuation of Table (12) (DERSA) AEP System "C" Variation

Version -2

	Interval 5			6			7		
Unit	ΔP	Value C	Range C	ΔP	Value C	Range C	ΔP	Value C	Range C
1	0	17.71	$0<C<\infty$	0	17.79	$0<C<\infty$	0	17.91	$0<C<\infty$
2	0	17.46	$0<C<\infty$	0	17.60	$0<C<\infty$	0	17.75	$0<C<\infty$
3	0	17.87	$0<C<\infty$	0	17.87	$0<C<\infty$	0	17.94	$0<C<\infty$
4	0	16.55	$0<C<\infty$	0	16.69	$0<C<\infty$	0	16.84	$0<C<\infty$
5	0	22.90	$0<C<\infty$	0	23.10	$0<C<'\infty$	0	23.20	$0<C<\infty$
6	0	22.90	$0<C<\infty$	0	23.10	$0<C<\infty$	0	23.20	$0<C<\infty$

Cont'd. on p. 83

Continuation of Table (12) (DERSA) AEP System "C" Variation

Version - 2

	Interval 8			9			10		
Unit	Value		Range		Value	Range		Value	Range
	ΔP	C	C	ΔP	C	C	ΔP	C	C
1	0	18.1	0<C<∞	0	18.2	0<C<∞	-1.79	18.3	-18.3<C<∞
2	0	17.9	0<C<∞	0	18.0	0<C<∞	1.79	18.2	-17.6<C<19.6*
3	0	18.1	0<C<∞	0	18.2	0<C<∞	0	18.4	-18.3<C<∞
4	0	16.9	0<C<17.2	0	17.1	0<C<∞	0	17.24	-18.32<C<∞
5	0	23.3	0<C<∞	0	23.5	0<C<∞	0	23.6	-18.32<C<18.2
6	0	23.3	0<C<∞	0	23.5	0<C<∞	0	23.6	-18.32<C<18.2

Cont'd. on p. 84

Continuation of Table (12) (DERSA) AEP System "C" Variation

Version - 2

Unit	Interval 11			12			13		
		Value	Range		Value	Range		Value	Range
	ΔP	C	C	ΔP	C	C	ΔP	C	C
1	0	18.5	$-18.4<C<\infty$	1.2	18.7	$-17.24<C<18.7$*	0	18.81	$17.4<C<\infty$
2	.3	18.3	$-17.4<C<19.8$*	-1.2	18.5	$-18.5<C<\infty$	0	18.6	$-18.7<C<\infty$
3	0	18.5	$-18.4<C<\infty$	0	18.7	$18.7<C<\infty$	0	18.8	$17.4<C<\infty$
4	-.3	17.24	$-18.4<C<\infty$	0	17.24	$18.7<C<\infty$	0	17.24	$17.4<C<\infty$
5	0	23.8	$-18.4<C<\infty$	0	23.9	$18.7<C<\infty$	0	24.1	$17.4<C<\infty$
6	0	23.84	$-18.4<C<\infty$	0	23.9	$18.7<C<\infty$	0	24.1	$17.4<C<\infty$

Cont'd. p. 85

Continuation of Table (12) (DERSA) AEP System "C" Variation

Version - 2

Unit	Interval 14 Value ΔP	C	Range C	15 ΔP	Value C	Range C	16 ΔP	Value C	Range C
1	0	18.9	$0<C<\infty$	0	19.1	$0<C<\infty$	0	19.19	$0<C<\infty$
2	0	18.78	$0<C<\infty$	0	18.9	$0<C<\infty$	0	19.0	$0<C<\infty$
3	0	18.9	$0<C<\infty$	0	19.1	$0<C<\infty$	0	19.2	$0<C<\infty$
4	0	17.24	$0<C<\infty$	0	17.24	$0<C<\infty$	0	17.24	$0<C<\infty$
5	0	24.2	$0<C<\infty$	0	24.4	$0<C<\infty$	0	24.5	$0<C<\infty$
6	0	24.2	$0<C<\infty$	0	24.4	$0<C<\infty$	0	24.5	$0<C<\infty$

CPU Time = 0.69 Seconds

Table (13): DERSA - AEP System Units outputs for
"C - Variation, Version -2"

Unit Output	Interval	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
	Load	1000	1030	1060	1110	1170	1240	1330	1420	1505	1590	1670	1750	1820	1885	1945	2000
	Cost	19311.1	19798.3	20288.6	21112.3	22108.9	23282.2	24803.6	26338.0	27799.0	29271.5	30699.7	32081.3	33327.3	34493.6	35577.9	36578.5
1	P^0	150.0	150.0	150.0	150.0	150.0	158.3	182.1	204.9	226.5	248.8	275.5	303.2	325.6	347.3	367.3	385.6
	$P^0 + \Delta P$	150.0	150.0	150.0	150.0	150.0	158.3	182.1	204.9	226.5	250.6	276.3	303.4	325.6	347.3	367.3	385.6
2		100.0	100.0	100.0	108.1	126.5	145.5	164.7	183.0	200.4	218.4	239.9	261.4	280.2	297.6	313.8	328.5
		100.0	100.0	100.0	108.1	126.5	145.5	164.7	183.0	200.4	216.6	240.2	260.2	280.2	297.6	313.8	328.5
3		50.0	50.0	50.0	50.0	50.0	50.0	53.8	61.2	68.2	75.5	84.1	92.8	100.3	107.3	113.8	119.8
		50.0	50.0	50.0	50.0	50.0	50.0	53.8	61.2	68.2	75.5	84.1	92.8	100.3	107.3	113.8	119.8
4		420.3	435.9	451.6	473.5	495.1	517.4	539.9	561.6	581.9	600.0	600.0	600.0	600.0	600.0	600.0	600.0
		420.3	435.9	451.6	473.5	495.1	517.4	539.9	561.6	581.9	600.0	597.7	600.0	600.0	600.0	600.0	600.0
5		139.9	147.0	154.2	164.2	174.2	184.4	194.7	204.6	213.9	223.7	235.2	246.8	256.9	266.4	275.1	283.0
		139.9	147.0	154.2	164.2	174.2	184.4	194.7	204.6	213.9	223.7	235.2	246.8	256.9	266.4	275.1	283.0
6		139.9	147.0	154.2	164.2	174.2	184.4	194.7	204.6	213.9	223.7	235.2	246.8	256.9	266.4	275.1	283.0
		139.9	147.0	154.2	164.2	174.2	184.4	194.7	204.6	213.9	223.7	235.2	246.8	256.9	266.4	275.1	283.0

CPU Time = is part of CPU time in table 12.

Table (14) (DERSA) CIGRE System

Load Variation "Increasing Load"

Units	Interval 1		2		3	
	10% load Increase (MW) 98		105 (MW)		131 (MW)	
	Max. actual feasible increase 380 (MW)		370 (MW)		170 (MW)	
	P (LP)	P (PLP)	P (LP)	P (PLP)	P (LP)	P (PLP)
1	110.0	134.5	118.7	145.2	149.0	153.7
2	30.0	52.0	30.0	52.0	30.0	52.0
3	43.8	66.2	48.0	71.6	63.5	76.1
4	122.3	147.3	130.9	157.4	161.1	165.8
5	40.0	68.0	40.0	68.0	40.0	68.0
6	40.0	68.0	40.0	68.0	48.0	68.3
7	40.0	68.0	40.0	68.0	44.4	68.0
8	108.0	134.2	115.6	143.0	143.0	151.1
9	100.4	126.0	108.6	135.4	138.0	143.6
10	86.0	111.0	95.0	120.2	130.5	130.5
11	84.0	108.9	93.4	118.9	127.5	128.4
12	95.3	121.0	104.0	130.3	135.0	138.9
13	40.0	68.0	40.0	68.0	51.0	67.8
14	40.0	68.0	40.0	68.0	49.3	68.0

Cont'd. on p. 88

Continuation of Table (14) (DERSA) CIGRE System

Load Variation "Increasing Load"

Units	Interval 4		5		6	
	10% load Increase 147 (MW)		167 (MW)		202 (MW)	
	Max. actual feasible increase 275 (MW)		202 (MW)		80 (MW)	
	P (LP)	P (PLP)	P (LP)	P (PLP)	P (LP)	P (PLP)
1	166.3	183.9	186.0	201.3	220.0	221.3
2	30.0	52.0	36.4	52.0	58.4	58.4
3	72.3	91.5	82.3	100.3	99.5	110.3
4	178.4	196.1	198.0	213.3	231.8	233.1
5	40.0	68.0	40.3	68.1	68.0	74.7
6	54.3	75.7	62.0	82.5	75.0	81.3
7	51.4	72.4	59.4	79.4	73.0	87.3
8	158.0	177.6	176.0	193.6	205.5	210.7
9	155.0	173.2	174.0	190.0	206.0	208.4
10	151.0	165.9	176.9	185.3	217.0	217.0
11	147.0	162.5	171.8	181.5	207.0	207.0
12	153.0	170.3	172.9	187.8	207.4	207.89
13	58.0	79.2	66.0	86.3	79.0	93.75
14	56.0	77.0	64.0	84.0	78.0	92.45

CPU Time 27.138 Seconds

Table (15) (DERSA) CIGRE System

Load Variation "Decreasing Load"

Units	Interval 1		2		3	
	Max. actual feasible decrease 126.2 (MW)		179.3 (MW)		281.9 (MW)	
	P (LP)	P (PLP)	P (LP)	P (PLP)	P (LP)	P (PLP)
1	110.0	80.0	118.7	84.5	149.0	115.1
2	30.0	30.0	30.0	30.0	30.0	30.0
3	43.8	41.0	48.0	41.0	63.5	43.5
4	122.3	88.2	130.9	96.0	161.1	126.1
5	40.0	40.0	40.0	40.0	40.0	40.0
6	40.0	40.0	40.0	40.0	48.0	41.0
7	40.0	40.0	40.0	40.0	44.4	41.3
8	108.0	80.0	115.6	81.6	143.0	109.2
9	100.4	80.4	108.6	81.0	138.0	104.6
10	86.0	80.0	95.0	80.7	130.5	97.9
11	84.0	80.0	93.4	80.0	127.5	95.5
12	95.3	90.0	104.0	89.1	135.0	101.6
13	40.0	40.0	40.0	40.0	51.0	41.6
14	40.0	40.0	40.0	40.0	49.3	41.0

Cont'd. on p. 90

Continuation of Table (15) (DERSA) CIGRE System

Load Variation "Decreasing Load"

Units	Interval 4		5		6	
	Max. actual feasible decrease 315.9 (MW)		352.9 (MW)		427.3 (MW)	
	P (LP)	P (PLP)	P (LP)	P (PLP)	P (LP)	P (PLP)
1	166.3	132.1	186.0	151.2	220.0	185.0
2	30.0	30.0	36.4	33.3	58.4	41.1
3	72.3	45.2	82.3	54.7	99.5	71.8
4	178.4	143.4	198.0	163.0	231.8	196.8
5	40.0	40.0	40.3	40.3	68.0	40.9
6	54.3	41.2	62.0	42.9	75.0	47.6
7	51.4	42.3	59.4	42.1	73.0	45.6
8	158.0	124.1	176.0	141.1	205.5	170.5
9	155.0	121.7	174.0	139.2	206.0	171.1
10	151.0	118.1	176.9	141.9	217.0	182.0
11	147.0	114.3	171.8	137.7	207.0	172.0
12	153.0	119.9	172.9	138.5	207.4	172.4
13	58.0	41.1	66.0	44.0	79.0	51.3
14	58.0	54.0	64.0	43.0	78.0	50.3

CPU time = 27.21 Seconds

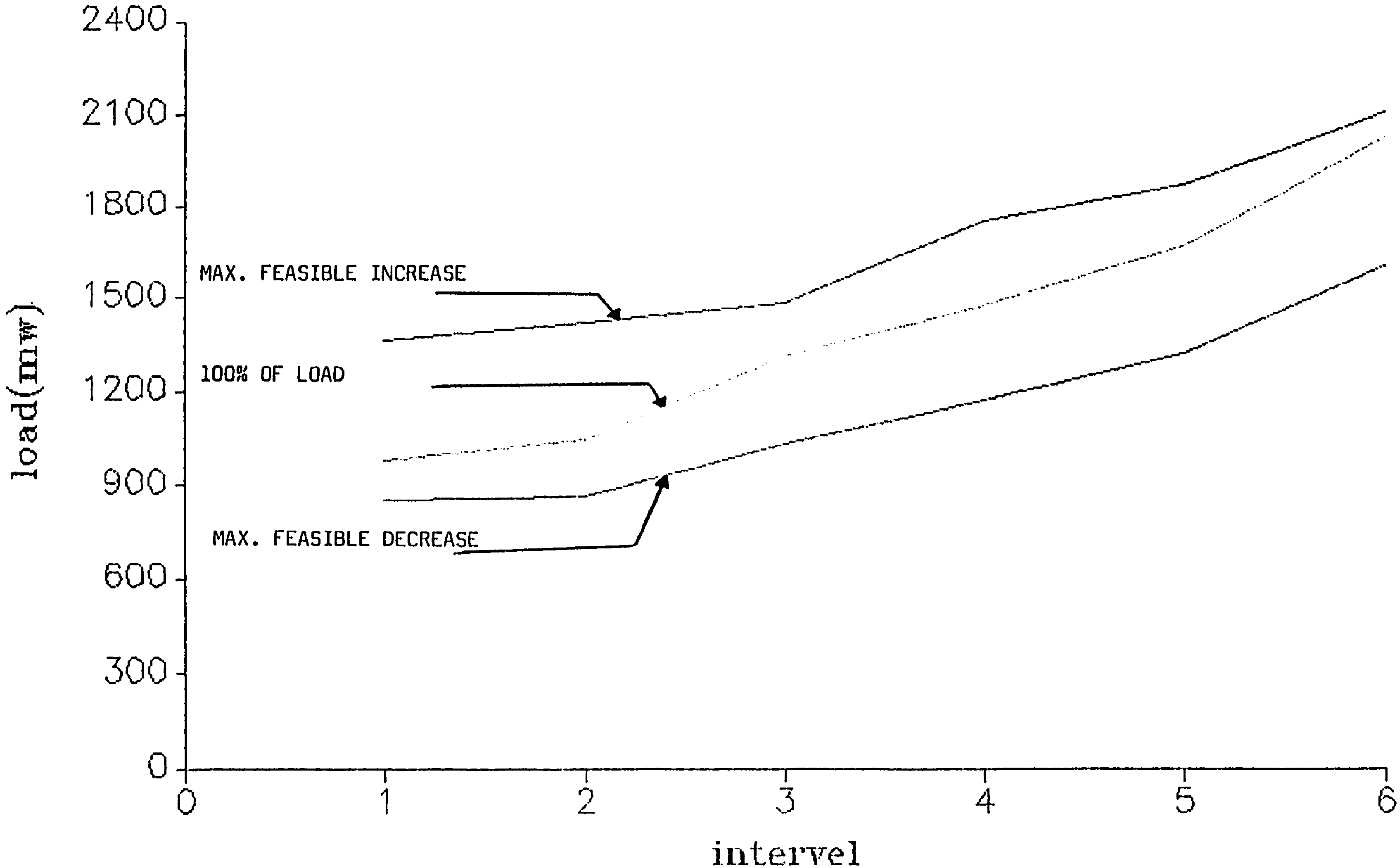


Figure No. (7)
LOAD-VARIATION CIGRE SYSTEM

Table (16) (DER) CIGRE System

"SHARP LOAD CURVE"

Units	Interval 1		2		3		4		5		6	
	Load	980		1415		1310		1745		1665		2020
	P^o	(ΔP) LP	P^o	(ΔP) LP	P^o	(ΔP) LP	P^o	(ΔP) LP	P^o	(ΔP) LP	P^o	(ΔP) LP
1	105.8	0	160.7	-19.8	148.4	6.77	197.9	-7.65	189	5.7	229.4	0
2	30	0	30	21.9	30	0	44	7.9	38	4.56	64.7	0
3	41.6	-.13	69.5	0	63.2	-2.87	88.3	0	84	0	104.4	0
4	117.9	.13	172.7	-19.8	160.5	0	210	-14.4	200.8	4.2	240	0
5	40	0	40	28	40	0	54.3	13.65	48.6	0	74.2	0
6	40	0	52.1	15.9	47.5	-7.4	66.3	1.73	62.8	0	78.3	0
7	40	0	49.1	18.9	44.1	-4.1	64.2	3.75	60.5	0	77	0
8	104.5	0	153.1	-13.6	142.3	8.85	186.1	0	178	1.1	214	0
9	96.2	0	149.1	-17.8	137.3	0	185	-12.7	176.2	4.3	215.5	0
10	113.1	0	202	-53.9	182	0	240	-22.8	240	-26.5	240	0
11	80	0	80	35	80	0	84.4	30.6	80	0	101	0
12	90.9	0	147	-21	134.5	15.6	185	0	176	6.64	217.3	0
13	40	0	55.7	12.3	51	-8.6	70.4	0	66.8	0	82.7	0
141	40	0	54	14.0	49.1	-8.13	69	0	65.2	0	81.6	0

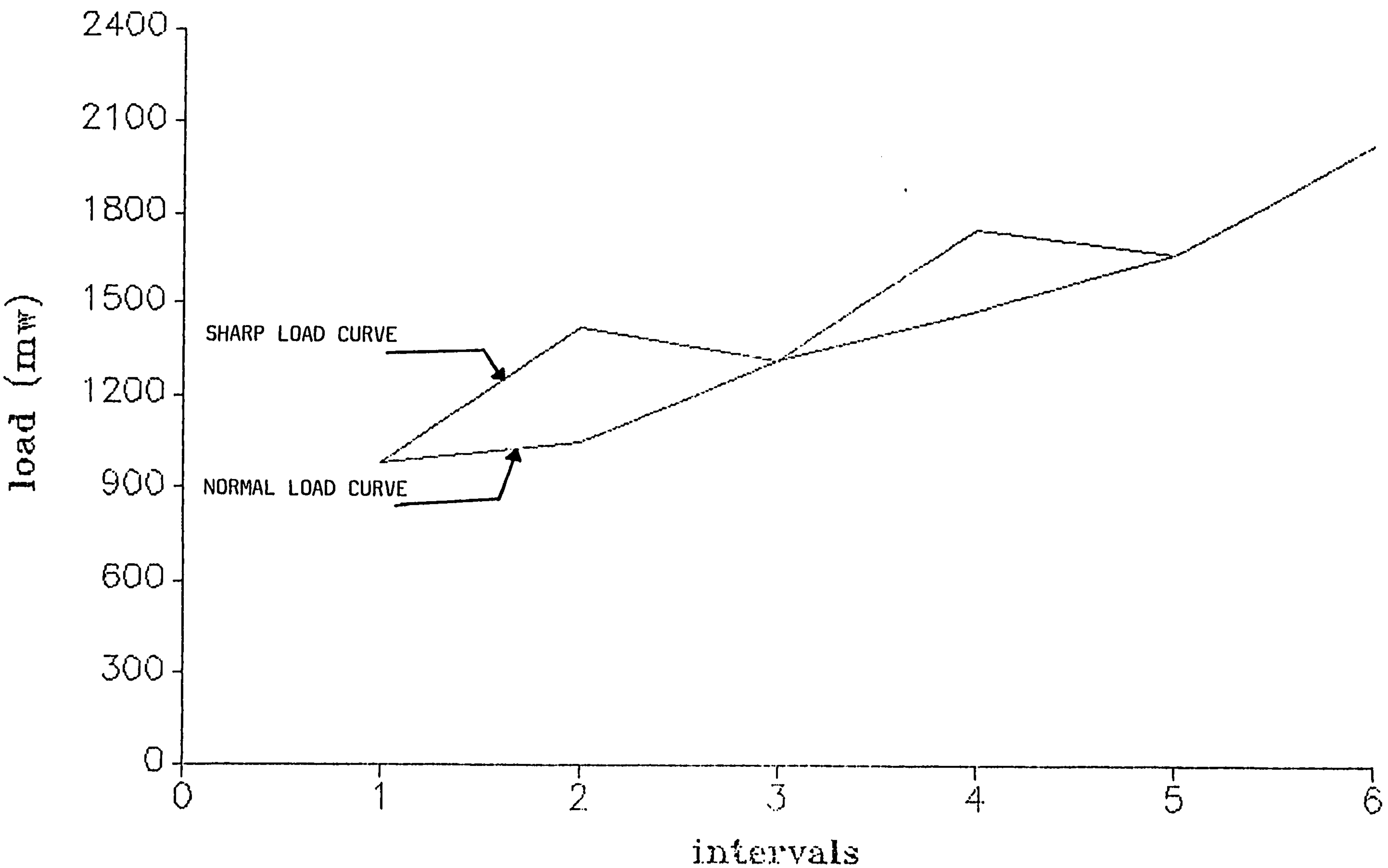


Figure No. (8)
SHARP LOAD CURVE CIGRE SYSTEM

Table (17) CIGRE System

(170 MW) Variation in load, interval - 3

Units	ΔP in Intervals					
	1	2	3	4	5	6
1	0.0	0.0	4.67	0.0	0.0	0.0
2	0.0	0.0	22.0	0.0	.012	0.0
3	0.0	0.0	12.6	0.0	0.0	0.0
4	0.0	0.0	4.67	0.0	0.0	0.0
5	0.0	0.0	28.0	0.0	-13.5	0.0
6	0.0	0.0	20.3	0.0	0.0	0.0
7	0.0	0.0	23.6	0.0	0.0	0.0
8	0.0	0.0	8.1	0.0	0.0	0.0
9	0.0	-.12	5.7	0.0	0.0	0.0
10	0.0	.061	0.0	0.0	3.97	0.0
11	0.0	0.0	0.94	0.0	2.86	0.0
12	0.0	0.0	3.95	0.0	-0.23	0.0
13	0.0	0.0	16.8	0.0	0.0	0.0
14	0.0	0.0	18.7	0.0	0.0	0.0

Table (18) (DERSA) AEP System

Load Variation "Increasing Load"

Units	Interval 1		2		3		4	
	10% load Increase 100 (MW)		103 (MW)		106 (MW)		111 (MW)	
	Max. actual feasible increase 135 (MW)		115 (MW)		115 (MW)		105 (MW)	
	P (LP)	P (PLP)	P (LP)	P (PLP)	P (LP)	P (PLP)	P (LP)	P (PLP)
1	150.0	185.0	150.0	185.0	150.0	185.0	150.0	185.0
2	100.0	120.0	100.0	120.0	100.0	120.0	100.0	120.0
3	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
4	365.4	399.9	377.4	405.4	389.3	417.0	409.2	430.1
5	167.3	190.3	176.3	192.3	185.4	201.4	200.4	214.9
6	167.3	190.3	176.3	192.3	185.4	201.4	200.4	214.9

Cont'd. on p/96

Continuation of Table (18) (DERSA) AEP System

Load Variation "Increasing Load"

Units	Interval 5		6		7		8	
	10% load Increase 117 (MW)		124 (MW)		133 (MW)		142 (MW)	
	Max. actual feasible increase 95 (MW)		85 (MW)		65 (MW)		65 (MW)	
	P (LP)	P (PLP)	P (LP)	P (PLP)	P (LP)	P (PLP)	P (LP)	P (PLP)
1	150.0	185.0	150.0	185.0	150.0	185.0	150.0	185.0
2	100.0	120.0	100.0	120.0	100.0	120.0	100.0	120.0
3	50.0	60.0	50.0	60.0	50.0	60.0	50.0	60.0
4	425.2	449.2	457.3	472.7	496.4	489.4	531	533.0
5	222.4	225.5	239.5	243.7	264.4	270.3	292.7	293.3
6	222.4	225.5	239.5	243.7	264.4	270.3	292.7	293.3

Cont'd. on p. 97

Continuation of Table (18) (DERSA) AEP System

Load Variation "Increasing Load"

Units	Interval 9		10		11		12	
	10% load Increase 150 (MW)		159 (MW)		167 (MW)		175 (MW)	
	Max. actual feasible increase 70 (MW)		70 (MW)		75 (MW)		75 (MW)	
	P (LP)	P (PLP)	P (LP)	P (PLP)	P (LP)	P (PLP)	P (LP)	P (PLP)
1	150.0	185.0	150.0	185.0	150.0	35.0	168.5	203.5
2	103.6	123.6	111.0	128.0	134.6	151.6	153.7	172.7
3	50.0	60.0	50.0	60.0	50.0	60.0	50.0	60.0
4	560.6	574.2	596.0	600.0	600.0	600.0	600.0	600.0
5	320.5	317.7	341.5	343.5	367.7	374.5	388.8	394.3
6	320.5	317.7	341.5	343.5	367.7	374.5	388.8	394.3

Cont'd. on p. 98

Continuation of Table (18) (DERSA) AEP System

Load Variation "Increasing Load"

Units	Interval 13		14		15		16	
	10% load Increase 182 (MW)		188 (MW)		194 (MW)		200 (MW)	
	Max. actual feasible increase 80 (MW)		90 (MW)		95 (MW)		70.1 (MW)	
	P (LP)	P (PLP)	P (LP)	P (PLP)	P (LP)	P (PLP)	P (LP)	P (PLP)
1	186.5	221.5	203.1	238.5	218.5	253.5	232.5	267.5
2	168.2	174.6	181.6	193.7	193.9	211.2	205.2	225.2
3	55.2	65.2	60.6	65.2	65.6	75.2	70.2	80.0
4	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0
5	404.9	419.6	419.8	438.9	433.5	450.0	446.0	448.0
6	404.9	419.6	419.8	438.9	433.5	450.0	446.0	448.0

CPU Time = 28.1 Seconds

Table (19) (DERSA) AEP System

Load Variation "Decreasing Load"

Units	Interval 1 Max. actual feasible decrease 107.9 (MW)		2 108.0 (MW)		3 108.0 (MW)		4 108.0 (MW)	
	P (LP)	P (PLP)	P (LP)	P (PLP)	P (LP)	P (PLP)	P (LP)	P (PLP)
1	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
2	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
3	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
4	365.4	316.3	377.4	328.2	389.3	340.1	409.2	360.0
5	167.3	137.9	176.4	147.0	185.4	156.0	200.4	171.0
6	167.3	137.9	176.4	147.0	185.4	156.0	200.4	171.0

Cont'd. on p. 100

Continuation of Table (19) (DERSA) AEP System

Load Variation "Decreasing Load"

Units	Interval 5 Max. actual feasible decrease 108.0 (MW)		6 108.9(MW)		7 108.9(MW)		8 108.9(MW)	
	P (LP)	P (PLP)	P (LP)	P (PLP)	P (LP)	P (PLP)	P (LP)	P (PLP)
1	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
2	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
3	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
4	425.2	375.5	457.3	407.6	496.4	446.9	531.0	481.3
5	222.4	192.9	239.5	210.0	264.4	234.9	292.7	263.2
6	222.4	192.9	239.5	210.0	264.4	234.9	292.7	263.2

Cont'd. on p. 101

Continuation of Table (19) (DERSA) AEP System

Load Variation "Decreasing Load"

Units	Interval 9 Max. actual feasible decrease 111.3(MW)		10 117.8(MW)		11 127.8(MW)		12 145.3(MW)	
	P (LP)	P (PLP)	P (LP)	P (PLP)	P (LP)	P (PLP)	P (LP)	P (PLP)
1	150.0	150.0	150.0	150.0	150.0	150.0	168.5	151.4
2	103.6	101.0	111.0	101.9	134.6	115.5	153.7	134.4
3	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
4	560.6	510.9	596.0	546.3	600.0	550.2	600.0	550.2
5	320.6	291.1	341.5	312.0	367.7	338.2	388.8	359.3
6	320.6	291.1	341.5	312.0	367.7	338.1	388.8	359.3

Cont'd. on p. 102

Continuation of Table (19) (DERSA) AEP System

Load Variation "Decreasing Load"

Units	Interval 13		14		15		16	
	Max. actual feasible decrease 166.3 (MW)		175.9 (MW)		180.1 (MW)		185.9 (MW)	
	P (LP)	P (PLP)	P (LP)	P (PLP)	P (LP)	P (PLP)	P (LP)	P (PLP)
1	186.5	151.4	203.1	164.2	218.5	179.4	232.5	193.4
2	168.2	148.8	181.6	162.2	193.9	174.4	205.2	185.7
3	55.2	52.1	60.6	51.4	65.6	52.5	70.2	51.5
4	600.0	550.2	600.0	550.2	600.0	550.2	600.0	550.2
5	404.9	375.3	419.8	390.5	433.5	404.2	446.0	416.6
6	404.9	375.4	419.8	390.2	433.5	404.1	446.0	416.6

CPU Time = 29.21 Seconds

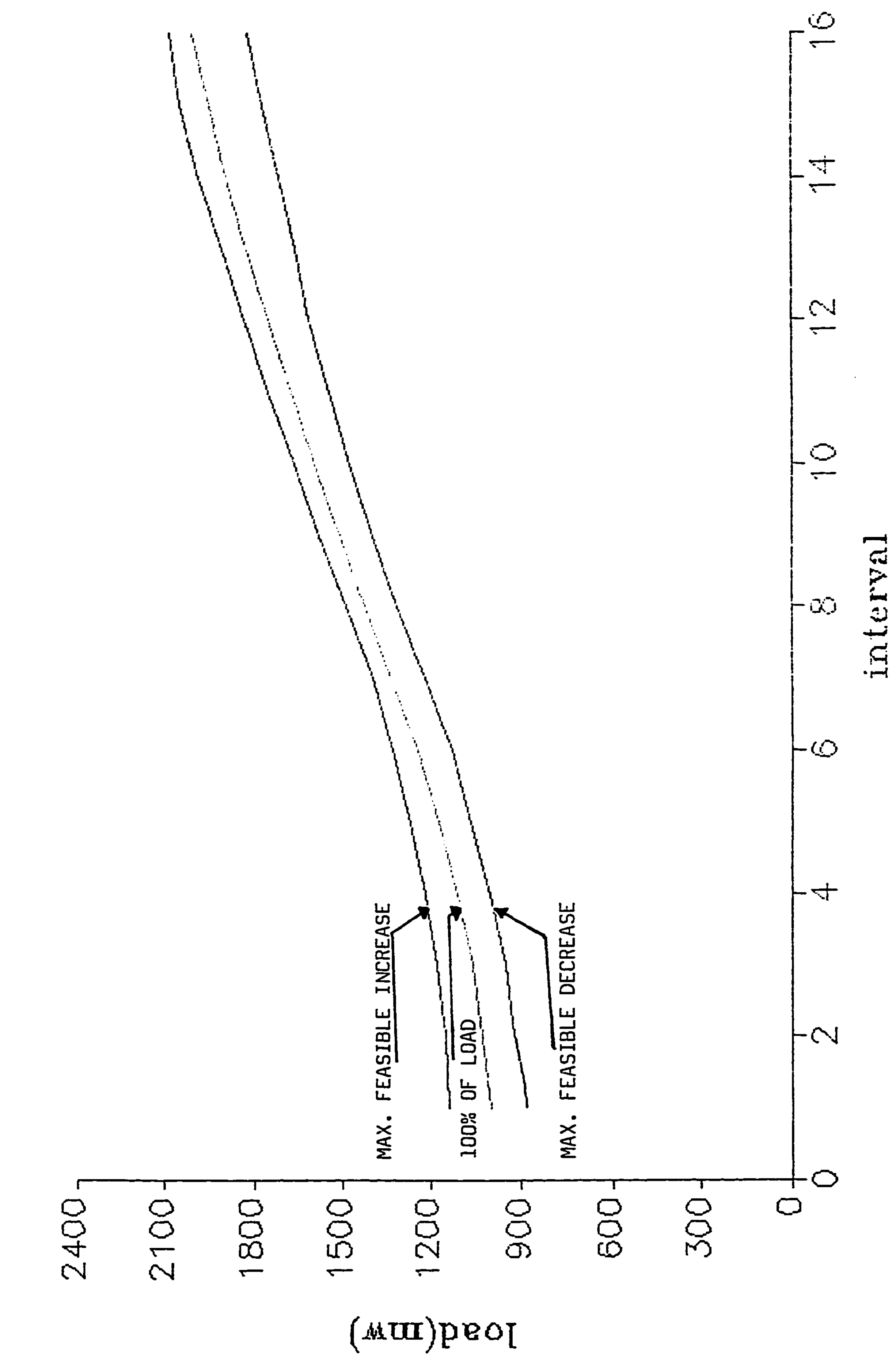


Figure No. (9)
LOAD-VARIATION AEP SYSTEM

Table - 20

CPU Time		
Method	CIGRE system	AEP System
SED	0.29	0.292
LP	0.23	0.231
PLP C-Variation	0.197	0.167
PLP Load Variation	26.62	27.58

4.3.2 Dynamic Economic Redispatch with Transmission Losses and Spinning Reserve in Sensitivity Analysis. (DERTSSA)

In this section transmission losses and spinning reserve are included in the dynamic economic redispatch with sensitivity analysis. The following constraints are added for section 4.3.1

Transmission n losses

$$\sum_{i=1}^{NG} \Delta P_{i,k} = P_d^k + P_{losses}^k - \sum_{i=1}^{NG} P_{i,k}^o = \delta P_d^k \qquad (4.10)$$

Spinning Reserve

$$-\Delta P_{i,k} - \Delta Y_{i,k} \leq RU_i + P_{i,k}^o + Y_{i,k}^o - P_{i,k}^{max} \qquad (4.11)$$

$$\Delta P_{i,k+1} - \Delta P_{i,k} - \Delta \eta_{i,k} \leq P_{i,k}^o + \eta_{i,k} - P_{i,k+1} \qquad (4.12)$$

$$\sum_{i=1}^{NG} (-2\Delta P_{i,k} + \Delta P_{i,k+1} - \Delta Y_{i,k} - \eta_{i,k}) \geq SR(k) + \Delta P_d^o +$$

$$\sum_{i=1}^{NG} 2P_{i,k}^o + Y_{i,k}^o + \eta_{i,k}^o - P_{i,k+1}^o - P_i^{max} \qquad (4.13)$$

First, the CIGRE and AEP systems wer tested without any parametric variations and after that parametric variation was included as shown in tables 21 - 28.

There are minor differences between the results obtained in this section and section 4.3.1. These differences are the increase in the units outputs due to the inclusion of the transmission losses and the increase in the execution time due to the inclusion of the spinning reserve. There is small increase in the values of the cost coefficient due to the increase of units loading after the inclusion of the transmission losses. The basic variables remains the same as in tables 8 and 11 (CIGRE & AEP Systems) and the new values of the cost coefficient remains to be within the ranges obtained in tables 8 and 11 for both CIGRE and AEP systems. The same notices and observations in section 4.3.1 are applicable here.

Table (21) : (DER) of CIGRE System with Network Losses

Unit Output		Interval 1	2	3	4	5	6
	Load	980	1045	1310	1470	1665	2020
	Cost	2414.63	2505.65	2919.46	3203.0	3575.62	4325.45
	Network Losses	4.85	5.16	7.08	10.43	13.05	16.09
	P^o	110.85	119.87	149.8	167.46	187.24	221.24
1	ΔP	0	0	0	0	0	0
	$P^o+\Delta P$	110.85	119.87	149.8	167.46	187.24	221.24
		30.0	30.0	30.0	30.0	37.17	59.38
2		0	0	0	0	.0116	0
		30.0	30.0	30.0	30.0	37.18	59.38
		44.13	48.46	63.9	72.9	82.97	100.26
3		0	0	0	0	0	0
		44.13	48.46	63.9	72.9	82.97	100.26
		122.94	131.46	161.9	179.55	199.3	233.3
4		0	0	0	0	0	0
		122.94	131.46	161.9	179.55	199.3	233.3
		40.0	40.0	40.0	40.0	54.35	69.1
5		0	0	0	0	-6.7	0
		40.0	40.0	40.0	40.0	47.65	69.1
		40.0	40.0	48.0	54.3	62.2	75.2
6		0	0	0	0	0	0
		40.0	40.0	48.0	54.3	62.2	75.2
		40.0	40.0	44.69	51.9	59.9	73.8
7		0	0	0	0	0	0
		40.0	40.0	44.69	51.9	59.9	73.8

Cont'd. on p. 108

Cont'd. Table (21)

Unit Output	Interval 1	2	3	4	5	6
	Load					
	980	1045	1310	1470	1665	2020
	Cost					
	2414.63	2505.65	2919.46	3203.0	3575.62	4325.45
	Netork Losses					
	4.85	5.16	7.08	10.43	13.05	16.09
	108.95	116.5	143.5	159.17	176.7	206.9
8	0	0	0	0	0	0
	108.95	116.5	143.5	159.17	176.7	206.9
	101.0	109.3	138.6	156.7	174.8	207.6
9	0	0	0	0	0	0
	101.0	109.3	138.6	156.7	174.8	207.6
	86.4	96.2	131.4	151.8	170.9	213.9
10	0	0	0	0	3.9	0
	86.4	96.2	131.4	151.8	174.8	213.9
	84.6	94.2	128.3	148.2	167.5	208.6
11	0	0	0	0	2.86	0
	84.6	94.2	128.3	148.2	170.4	208.6
	96.0	104.7	135.9	153.9	174.1	208.9
12	0	0	0	0	-.114	0
	96.0	104.7	135.9	153.9	174.2	208.9
	40.0	40.0	51.5	58.4	66.2	79.5
13	0	0	0	0	0	0
	40.0	40.0	51.5	58.4	66.2	79.5

Cont'd. on p. 109

Cont'd. Table (21)

Unit Output	Interval 1	2	3	4	5	6
	Load					
	980	1045	1310	1470	1665	2020
	Cost					
	2414.63	2505.65	2919.46	3203.0	3575.62	4325.45
	Network Losses					
	4.85	5.16	7.08	10.43	13.05	16.09
	40.0	40.0	49.6	56.7	64.7	78.3
14	0	0	0	0	0	0
	40.0	40.0	49.6	56.7	64.7	78.3

CPU Time = = 0.63 Seconds

TABLE (22) : (DER) of AEP System with Network losses

Unit Output		Interval 1	2	3	4	5	6	7	8
	Load	1000	1030	1060	1110	1170	1240	1330	1420
	Cost	19097.2	19560.4	20025.9	20806.4	21750.3	22862.4	24305.9	25773.3
	Network Losses	3.87	4.0	4.12	4.4	4.7	5.1	5.6	6.5
1	P^o	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
	ΔP	0	0	0	0	0	0	0	0
	$P^o+\Delta P$	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
2		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
		0	0	0	0	0	0	0	0
		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
3		50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
		0	0	0	0	0	0	0	0
		50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
4		366.9	378.9	390.9	410.9	442.8	466.7	498.6	533.7
		0	0	0	0	-7.9	-3.7	.43	1.58
		366.9	378.9	390.3	410.9	434.9	463.0	499.0	535.3
5		168.5	177.5	186.6	201.7	215.9	239.2	270.5	296.4
		0	0	0	0	3.93	1.86	-2.2	-.79
		168.5	177.5	186.6	201.7	219.9	241.1	268.3	295.6
6		168.5	177.5	186.6	201.7	219.9	239.2	270.5	296.4
		0	0	0	0	3.93	1.86	-2.2	-.79
		168.5	177.5	186.6	201.7	219.9	241.1	268.3	295.6

Cont'd. on p. 111

Continuation of Table (22) : (DER) of AEP System with Network losses

Unit Output		Interval 9	10	11	12	13	14	15	16
		Load							
		1505	1590	1670	1750	1820	1885	1945	2000
		Cost							
		27174.6	28589.1	29943.8	31313.3	32520.7	33649.8	34700.0	35669.4
		Network Losses							
		7.3	8.2	9.3	10.6	11.8	12.9	14.0	15.2
1	P^o	150.0	150.0	150.0	171.2	189.6	206.4	220.0	236.4
	ΔP	0	0	0	0	0	0	0	0
	$P^o+\Delta P$	150.0	150.0	150.0	171.2	189.6	206.44	222.0	236.4
2		100.0	112.8	137.5	156.0	170.7	184.3	196.8	208.4
		3.6	0	0	0	0	0	0	0
		103.6	112.8	137.5	156.0	170.7	184.3	196.8	208.4
3		50.0	50.0	50.0	50.4	56.2	61.7	66.8	71.4
		0	0	0	0	0	0	0	0
		50.0	50.0	50.0	50.4	56.2	61.7	66.8	71.4
4		575.3	598.5	600.0	600.0	600.0	600.0	600.0	600.0
		-5.94	0	0	0	0	0	0	0
		569.4	598.5	600.0	600.0	600.0	600.0	600.0	600.0
5		320.3	343.4	370.9	391.4	407.7	422.7	436.7	449.5
		1.2	0	0	0	0	0	0	0
		321.5	343.4	370.9	391.4	407.7	422.7	436.7	449.5
6		320.3	344.4	370.9	391.4	404.9	422.7	436.7	449.5
		1.2	0	0	0	0	0	0	0
		321.5	343.4	370.9	391.4	407.7	422.7	436.7	449.5
CPU Time				= 1.4 Seconds					

TABLE (23) : (DER) of AEP System with Network losses and Spinning Reserve

Unit Output		Interval 1	2	3	4	5	6	7	8
		Load 1000	1030	1060	1110	1170	1240	1330	1420
		Cost 19097.2	19560.4	20025.9	20806.4	21750.3	22862.4	24305.9	25773.3
		Network Losses 3.87	4.0	4.12	4.4	4.7	5.1	5.6	6.5
		Spinning Reserve 124.9	124.8	86.1	93.5	84.7	64.7	64.4	68.1
1	P^o	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
	ΔP	0	0	0	0	0	0	0	0
	$P^o+\Delta P$	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
2		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
		0	0	0	0	0	0	0	0
		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
3		50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
		0	0	0	0	0	0	0	0
		50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
4		366.9	378.9	390.9	410.9	442.8	466.7	498.6	533.7
		0	0	0	0	-7.9	-3.7	.43	1.58
		366.9	378.9	390.3	410.9	434.9	463.0	499.0	535.3
5		168.5	177.5	186.6	201.7	215.9	239.2	270.5	296.4
		0	0	0	0	3.93	1.86	-2.2	-.79
		168.5	177.5	186.6	201.7	219.9	241.1	268.3	295.6
6		168.5	177.5	186.6	201.7	219.9	239.2	270.5	296.4
		0	0	0	0	3.93	1.86	-2.2	-.79
		168.5	177.5	186.6	201.7	219.9	241.1	268.3	295.0

Cont'd. on p. 113

Continuation of Table (23) : (DER) of AEP System with Network losses and Spinning Reserve

Unit Output		Interval 9	10	11	12	13	14	15	16
	Load	1505	1590	1670	1750	1820	1885	1945	2000
	Cost	27174.6	28589.1	29943.8	31313.3	32520.7	33649.8	34700.0	35669.4
	Network Losses	7.3	8.2	9.3	10.6	11.8	12.9	14.0	15.2
	Spinning Reserve	60.0	72.9	73.7	75.4	74.6	78.1	72.2	155
1	P^0	150.0	150.0	150.0	171.2	189.6	206.4	220.0	236.4
	ΔP	0	0	0	0	0	0	0	0
	$P^0+\Delta P$	150.0	150.0	150.0	171.2	189.6	206.44	220.0	236.4
2		100.0	112.8	137.5	156.0	170.7	184.3	196.8	208.4
		3.6	0	0	0	0	0	0	0
		103.6	112.8	137.5	156.0	170.7	184.3	196.8	208.4
3		50.0	50.0	50.0	50.4	56.2	61.7	66.8	71.4
		0	0	0	0	0	0	0	0
		50.0	50.0	50.0	50.4	56.2	61.7	66.8	71.4
4		575.3	598.5	600.0	600.0	600.0	600.0	600.0	600.0
		-5.94	0	0	0	0	0	0	0
		569.4	598.5	600.0	600.0	600.0	600.0	600.0	600.0
5		320.3	343.4	370.9	391.4	407.7	422.7	436.7	449.5
		1.2	0	0	0	0	0	0	0
		321.5	343.4	370.9	391.4	407.7	422.7	436.7	449.5
6		320.3	344.4	370.9	391.4	404.9	422.7	436.7	449.5
		1.2	0	0	0	0	0	0	0
		321.5	343.4	370.9	391.4	407.7	422.7	436.7	449.5
CPU Time				= 21.2	Seconds				

Table (24) : (DER) of CIGRE System with Network Losses

and Spinning Reserve

Unit Output		Interval 1	2	3	4	5	6
		Load					
		980	1045	1310	1470	1665	2020
		Cost					
		2414.63	2505.65	2919.46	3203.0	3575.62	4325.45
		Network Losses					
		4.85	5.16	7.08	10.43	13.05	16.09
		Spinning Reserve					
		220	170	140	115	88	80
	P^o	110.85	119.87	149.8	167.46	187.24	221.24
1	ΔP	0	0	0	0	0	0
	$P^o+\Delta P$	110.85	119.87	149.8	167.46	187.24	221.24
		30.0	30.0	30.0	30.0	37.17	59.38
2		0	0	0	0	.0116	0
		30.0	30.0	30.0	30.0	37.18	59.38
		43.13	48.46	63.9	72.9	82.97	100.26
3		0	0	0	0	0	0
		43.13	48.46	63.9	72.9	82.97	100.26
		122.94	131.46	161.9	179.55	199.3	233.3
4		0	0	0	0	0	0
		122.04	131.46	161.9	179.55	199.3	233.3
		40.0	40.0	40.0	40.0	54.35	69.1
5		0	0	0	0	-6.7	0
		40.0	40.0	40.0	40.0	47.65	69.1
		40.0	40.0	48.0	54.3	62.2	75.2
6		0	0	0	0	0	0
		40.0	40.0	48.0	54.3	62.2	75.2

Cont'd. on p. 115

Cont'd. Table (24)

Unit Output	Interval 1	2	3	4	5	6
	Load					
	980	1045	1310	1470	1665	2020
	Cost					
	2414.63	2505.65	2919.46	3203.0	3575.62	4325.45
	Netork Losses					
	4.85	5.16	7.08	10.43	13.05	16.09
	Spinning Reserve					
	220	170	140	115	88	80
7	40.0	40.0	44.69	51.9	59.9	73.8
	0	0	0	0	0	0
	40.0	40.0	44.69	51.9	59.9	73.8
	108.95	116.5	143.5	159.17	176.7	206.9
8	0	0	0	0	0	0
	108.95	116.5	143.5	159.17	176.7	206.9
	101.0	109.3	138.6	156.7	174.8	207.6
9	0	0	0	0	0	0
	101.0	109.3	138.6	156.7	174.8	207.6
	86.4	96.2	131.4	151.8	170.9	213.9
10	0	0	0	0	3.9	0
	86.4	96.2	131.4	151.8	174.8	213.9
	84.6	94.2	128.3	148.2	167.5	208.6
11	0	0	0	0	2.86	0
	84.6	94.2	128.3	148.2	170.4	208.6
	96.0	104.7	135.9	153.9	174.1	208.9
12	0	0	0	0	-.114	0
	96.0	104.7	135.9	153.9	174.2	208.9

Cont'd. on p. 116

Cont'd. Table (24)

Unit Output	Interval 1	2	3	4	5	6
	Load 980	1045	1310	1470	1665	2020
	Cost 2414.63	2505.65	2919.46	3203.0	3575.62	4325.45
	Network Losses 4.85	5.16	7.08	10.43	13.05	16.09
	Spinning Reserve 220	170	140	115	88	80
13	40.0	40.0	51.5	58.4	66.2	78.5
	0	0	0	0	0	0
	40.0	40.0	51.5	58.4	66.2	79.5
	40.0	40.0	49.6	56.7	64.7	78.3
14	0	0	0	0	0	0
	40.0	40.0	49.6	56.7	64.7	78.3

CPU Time = = 9.1 Seconds

Table (25): DER of CIGRE System with Network losses,

Spinning Reserve in Sensitivity Analysis

"C Variation"

Units	Interval 1 ΔP	1 Value C	1 Range C	2 ΔP	2 Value C	2 Range C	3 ΔP	3 Value C	3 Range C
1	0	1.99	0<C<∞	0	2.06	-1.98<C<∞	0	2.295	1.74<C<∞
2	0	2.235	0<C<∞	0	2.35	-1.98<C<∞	0	2.35	1.74<C<∞
3	0	1.963	0<C<∞	0	2.05	-1.98<C<∞	0	2.28	1.74<C<∞
4	0	1.99	0<C<∞	0	2.056	-1.98<C<∞	0	2.295	1.74<C<∞
5	0	2.364	0<C<∞	0	2.328	-1.98<C<∞	0	2.36	1.74<C<∞
6	0	2.328	0<C<∞	0	2.33	-1.98<C<∞	0	2.49	1.74<C<∞
7	0	2.349	0<C<∞	0	2.34	-1.98<C<∞	0	2.44	1.74<C<∞
8	0	2.065	0<C<∞	0	2.13	-1.98<C<∞	0	2.37	1.74<C<∞
9	0	2.01	0<C<∞	0	2.079	-1.98<C<∞	0	2.32	1.74<C<∞
10	0	1.75	0<C<∞	0	1.814	-1.97<C<∞	0	2.054	2.2<C<∞
11	0	1.915	0<C<∞	0	1.987	-1.98<C<∞	0	2.23	1.74<C<∞
12	0	1.97	0<C<∞	0	2.044	-1.98<C<∞	0	2.284	1.74<C<∞
13	0	2.243	0<C<∞	0	2.24	-1.98<C<∞	0	2.478	1.74<C<∞
14	0	2.261	0<C<∞	0	2.26	-1.98<C<∞	0	2.45	1.74<C<∞

Cont'd. on p. 118

Cont'd. Table (25)

Units	Interval 4 ΔP	Value C	Range C	5 ΔP	Value C	Range C	6 ΔP	Value C	Range C
1	0	2.43	0<C<∞	0	2.59	−2.57<C<∞	0	2.86	2.3 <C<∞
2	0	2.24	0<C<∞	.0116	2.32	−2.3 <C<∞	0	2.59	−2.58<C<∞
3	0	2.42	0<C<∞	0	2.58	2.56<C<∞	0	2.85	2.3 <C<∞
4	0	2.43	0<C<∞	0	2.59	−2.56<C<∞	0	2.86	2.3 <C<∞
5	0	2.36	0<C<∞	-6.7	2.54	−2.45<C<∞	0	2.72	2.2 <C<∞
6	0	2.62	0<C<∞	0	2.78	−2.57<C<∞	0	3.05	2.3 <C<∞
7	0	2.58	0<C<∞	0	2.73	−2.57<C<∞	0	3.00	2.3 <C<∞
8	0	2.51	0<C<∞	0	2.66	−2.57<C<∞	0	2.93	2.3 <C<∞
9	0	2.47	0<C<∞	0	2.61	−2.57<C<∞	0	2.88	2.3 <C<∞
10	0	2.19	0<C<∞	3.9	2.32	−2.56<C<3.025	0	2.61	−2.76 <C<∞
11	0	2.37	0<C<∞	2.86	2.51	−2.51<C<2.511	0	2.78	−2.78 <C<∞
12	0	2.42	0<C<∞	−.114	2.58	−2.57<C<∞	0	2.84	2.3 <C<∞
13	0	2.62	0<C<∞	0	2.77	−2.57<C<∞	0	3.01	2.3 <C<∞
14	0	2.59	0<C<∞	0	2.75	−2.57<C<∞	0	3.01	2.3 <C<∞

CPU

Time = 9.29 Seconds

Table (26) DER of AEP System with Network losses,

Spinning Reserve in Sensitivity Analysis

"C" Variation

Unit	Interval 1 ΔP	Value C	Range C	2 ΔP	Value C	Range C	3 ΔP	Value C	Range C	4 ΔP	Value C	Range C
1	0	17.71	0<C<∞	0	17.71	0<C<∞	0	17.71	0<C<∞	0	17.71	0<C<∞
2	0	17.25	0<C<∞	0	17.3	0<C<∞	0	17.25	0<C<∞	0	17.25	0<C<∞
3	0	17.9	0<C<∞	0	17.87	0<C<∞	0	17.87	0<C<∞	0	17.87	0<C<∞
4	0	16.14	0<C<∞	0	16.21	0<C<∞	0	16.30	0<C<∞	0	16.38	0<C<∞
5	0	16.05	0<C<∞	0	16.1	0<C<∞	0	16.17	0<C<∞	0	16.3	0<C<∞
6	0	16.05	0<C<∞	0	16.1	0<C<∞	0	16.17	0<C<∞	0	16.3	0<C<∞

Cont'd. on p. 120

Continuation of Table (26)

Unit	Interval 5			6			7		
	ΔP	Value C	Range C	ΔP	Value C	Range C	ΔP	Value C	Range C
1	0	17.71	$0<C<\infty$	0	17.71	$-16.6<C<\infty$	0	17.71	$-16.8<C<\infty$
2	0	17.25	$0<C<\infty$	0	17.25	$-16.6<C<\infty$	0	17.25	$-16.83<C<\infty$
3	0	17.87	$0<C<\infty$	0	17.87	$-16.6<C<\infty$	0	17.87	$-16.83<C<\infty$
4	0	16.54	$0<C<\infty$	-7.88	16.67	$-16.6<C<\infty$	-3.72	16.84	$-16.83<C<\infty$
5	0	16.4	$1.5<C<\infty$	3.94	16.54	$1.64<C<18.04$	1.86	16.76	$1.83<C<18.2$
6	0	16.4	$1.5<C<\infty$	3.94	16.54	$1.64<C<18.04$	1.86	16.76	$1.83<C<18.2$

Cont'd. on p. 121

Continuation of Table (26)

Unit	Interval 8			9			10		
		Value	Range		Value	Range		Value	Range
	ΔP	C	C	ΔP	C	C	ΔP	C	C
1	0	17.71	$17.0<C<\infty$	0	17.1	$17.1<C<\infty$	0	17.71	$-17.4<C<\infty$
2	0	17.25	$17.0<C<\infty$	0	17.25	$17.2<C<\infty$	3.6	17.35	$-17.3<C<17.34$
3	0	17.87	$17.0<C<\infty$	0	17.87	$17.2<C<\infty$	0	17.87	$-17.4<C<\infty$
4	0.43	17.03	$15.5<C<17.2$	1.58	17.2	$15.7<C<17.3$	-5.94	17.4	$-17.4<C<\infty$
5	-.22	16.94	$16.9<C<\infty$	-0.79	17.1	$-17.1<C<\infty$	1.18	17.27	$17.3<C<17.8$
6	-.22	16.94	$16.9<C<\infty$	-0.79	17.1	$-17.1<C<\infty$	1.18	17.27	$17.3<C<17.8$

Cont'd. on p. 122

Continuation of Table (26)

	Interval	11		12			13		
Unit		Value	Range		Value	Range		Value	Range
	ΔP	C	C	ΔP	C	C	ΔP	C	C
1	0	17.71	$17.1<C<\infty$	0	17.85	$0<C<\infty$	0	17.96	$0<C<\infty$
2	0	17.54	$-17.5<C<\infty$	0	17.69	$0<C<\infty$	0	17.8	$0<C<\infty$
3	0	17.87	$17.2<C<\infty$	0	17.87	$0<C<\infty$	0	17.99	$0<C<\infty$
4	0	17.4	$17.2<C<\infty$	0	17.4	$0<C<\infty$	0	17.4	$0<C<\infty$
5	0	17.46	$-17.4<C<\infty$	0	17.61	$0<C<\infty$	0	17.72	$0<C<18.2$
6	0	17.46	$-17.4<C<\infty$	0	17.61	$0<C<\infty$	0	17.72	$0<C<18.2$

Cont'd. on p. 123

Continuation of Table (26)

Interval	14			15			16		
Unit		Value	Range		Value	Range		Value	Range
	ΔP	C	C	ΔP	C	C	ΔP	C	C
1	0	18.1	0<C<∞	0	18.2	0<C<∞	0	18.25	0<C<∞
2	0	17.91	0<C<∞	0	18.00	0<C<∞	0	18.1	0<C<∞
3	0	18.1	0<C<∞	0	18.2	0<C<∞	0	18.3	0<C<∞
4	0	17.4	0<C<∞	0	17.4	0<C<∞	0	17.4	0<C<∞
5	0	17.83	0<C<∞	0	17.92	0<C<∞	0	18.01	0<C<∞
6	0	17.83	0<C<∞	0	17.92	0<C<∞	0	18.01	0<C<∞

CPU Time = 21.36 Seconds

Table (27) DER of CIGRE System with Network losses,

Spinning Reserve in Sensitivity Analysis

Load Variation "Increasing Load"

Units	Interval 1		2		3	
	10% load Increase (MW) 98		105 (MW)		131 (MW)	
	Max. actual feasible increase 380 (MW)		370 (MW)		170 (MW)	
	P (LP)	P (PLP)	P (LP)	P (PLP)	P (LP)	P (PLP)
1	110.85	135.4	119.87	146.4	149.8	154.5
2	30.0	52.0	30.0	52.0	30.0	52.0
3	43.1	65.5	48.46	72.1	63.9	76.5
4	122.04	147.04	131.5	158.0	161.9	166.5
5	40.0	68.0	40.0	68.0	40.0	68.0
6	40.0	68.0	40.0	68.0	40.0	60.3
7	40.0	68.0	40.0	68.0	44.7	68.3
8	108.9	135.1	116.5	143.9	143.5	151.6
9	101.0	126.8	109.3	136.1	138.6	144.2
10	86.4	111.5	96.2	121.4	131.4	131.4
11	84.6	109.5	94.3	119.7	128.3	129.2
12	96.0	121.7	104.7	131.0	135.9	139.9
13	40.0	68.0	40.0	68.0	51.5	68.3
14	40.0	68.0	40.0	68.0	49.6	68.3

Cont'd. on p. 125

Continuation of Table (27)

Load Variation "Increasing Load"

Units	Interval 4		5		6	
	10% load Increase 147 (MW)		167 (MW)		202 (MW)	
	Max. actual feasible increase 275 (MW)		202 (MW)		80 (MW)	
	P (LP)	P (PLP)	P (LP)	P (PLP)	P (LP)	P (PLP)
1	167.5	185.1	187.2	202.5	221.2	222.5
2	30.0	52.0	37.2	52.8	59.4	59.4
3	72.9	92.1	82.9	100.9	100.3	111.1
4	170.6	197.3	199.3	214.6	233.3	234.6
5	40.0	68.0	47.7	68.8	69.1	75.8
6	54.3	75.7	62.2	82.7	75.2	83.5
7	51.9	72.9	59.9	79.9	73.8	88.1
8	159.2	178.8	176.7	194.3	206.9	212.1
9	156.7	174.9	174.8	190.8	207.6	210
10	151.8	166.7	174.8	187.1	213.9	213.9
11	148.2	163.7	170.4	183.3	208.6	208.6
12	153.9	171.2	174.2	189	208.9	208.6
13	58.4	79.6	66.2	86.2	79.5	79.5
14	56.7	77.7	64.7	84.7	78.3	78.3

CPU Time = 35.96 Seconds

Table (28) DER of AEP System with Network losses,

Spinning Reserve in Sensitivity Analysis

Load Variation "Increasing Load"

Units	Interval 1		2		3		4	
	10% load Increase 100 (MW)		103 (MW)		106 (MW)		111 (MW)	
	Max. actual feasible increase 135 (MW)		115 (MW)		115 (MW)		105 (MW)	
	P (LP)	P (PLP)	P (LP)	P (PLP)	P (LP)	P (PLP)	P (LP)	P (PLP)
1	150.0	185.0	150.0	185.0	150.0	185.0	150.0	185.0
2	100.0	120.0	100.0	120.0	100.0	120.0	100.0	120.0
3	50.0	50.0	50.0	60.0	50.0	60.0	50.0	60.0
4	366.9	400.5	378.9	406.0	390.9	419.0	410.9	431.9
5	168.5	191.5	177.5	193.5	186.6	202.6	201.7	211.7
6	168.5	191.5	177.5	193.5	186.6	202.6	201.7	211.7

Cont'd. on p. 127

Continuation of Table (28)

Units	Interval 5		6		7		8	
	10% load Increase 117 (MW)		124 (MW)		133 (MW)		142 (MW)	
	Max. actual feasible increase 95 (MW)		85 (MW)		65 (MW)		65 (MW)	
	P (LP)	P (PLP)	P (LP)	P (PLP)	P (LP)	P (PLP)	P (LP)	P (PLP)
1	150.0	185.0	150.0	185.0	150.0	185.0	150.0	185.0
2	100.0	120.0	100.0	120.0	100.0	120.0	100.0	120.0
3	50.0	60.0	50.0	60.0	50.0	60.0	50.0	60.0
4	434.9	458.9	463.0	478.4	499.0	491.6	535.3	534.1
5	219.9	222.9	241.1	245.3	268.3	272.0	295.6	295.9
6	219.9	222.9	241.1	245.3	268.3	272.0	295.6	295.9

Cont'd. on p. 128

Continuation of Table (28)

Units	Interval 9		10		11		12	
	10% load Increase 150 (MW)		159 (MW)		167 (MW)		175 (MW)	
	Max. actual feasible increase 70 (MW)		70 (MW)		75 (MW)		75 (MW)	
	P (LP)	P (PLP)	P (LP)	P (PLP)	P (LP)	P (PLP)	P (LP)	P (PLP)
1	150.0	185.0	150.0	185.0	150.0	185.0	171.2	206.2
2	103.6	120.0	112.8	129.8	137.5	144.5	156.0	175.0
3	50.0	60.0	50.0	60.0	50.0	60.0	50.4	60.4
4	569.4	582.9	598.5	598.5	600.0	600.0	600.0	600.0
5	321.5	318.7	343.4	346.4	370.9	377.7	391.4	396.9
6	321.5	318.7	343.4	346.4	370.9	377.7	391.4	396.9

Cont'd. on p. 129

Continuation of Table (28)

Units	Interval 13		14		15		16	
	10% load Increase 182 (MW)		188 (MW)		194 (MW)		200 (MW)	
	Max. actual feasible increase 80 (MW)		90 (MW)		95 (MW)		65 (MW)	
	P (LP)	P (PLP)	P (LP)	P (PLP)	P (LP)	P (PLP)	P (LP)	P (PLP)
1	189.6	224.6	206.4	241.4	220.0	255	236.4	271.4
2	170.7	177.1	184.3	196.3	196.8	214.1	208.4	228.4
3	56.2	66.2	61.7	66.3	66.8	76.4	71.4	81.9
4	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0
5	407.7	422.4	422.7	441.8	436.7	453,2	449.5	449.5
6	404.9	422.4	422.7	444.8	436.7	453.2	449.5	449.5

CPU Time = Seconds

4.3.3 Dynamic Economic Redispatch with Transmission Losses, Spinning Reserve, and Security Constraints

In this section security constraint is added to the redispatch problem. It is assumed that contingency analysis was already performed and some lines will be heavily overloaded. Security constraint was included in the formulation to prevent the lines overloading. The representation of the lines loadings are expressed in terms of the units outputs using the GGDF [8]. The AEP system is chosen here as a test case and the analysis is valid for any other system. Lines 11, 18, and 22 are considered to be heavily overloaded whenever a contingency event occurs. The GGDF are calculated using another separate program. Table 26 shows the results of the dynamic economic redispatch considering all the constraints including the security constraints and the following are the observations:

1- The basic equation of the spinning reserve was considered, i.e. equation 4.12, in order to satisfy spinning reserve requirements. The units moved up and down to satisfy both spinning reserve requirements and security constraints and when a unit was moved down the spinning reserve was not met. Since the amount by which the unit was moved down was considered as part of the reserve requirements. In this case the second term of the spinning reserve was considered, equation 4.13, and it becomes active only when a unit output is moved down. It actually deducts the amount of decrease in that unit from the spinning reserve computaion. In this case spinning reserve requirements are alsways satisfied in all conditions. the increase in the execution time here is due to the inclusion of the second term of the spinning reserve.

2- As seen from table (29) it was not possible to prevent the lines overloading and this program tells the power system dispatcher in the power control center about this fact. During some contingencies some lines are subject to overload but for many hours and a certain percentage can be tolerated during the hours of overloading. Usually Power System Operation Departments have emergency loading hours of the transmission lines through out the year. In this case it depends on the condition of the lines, i.e., if it is within the operational limit that the power dispatchers have or, if it is not, they have to do load shedding to alliviate this overload. Table (29) shows the overloading start at interval 12 and the maximum overload occurred at interval 16.

TABLE (29) : (DER) of AEP System with Network losses,

Spinning Reserve and Security Constraints

Unit	Output	Interval 1	2	3	4	5	6	7	8
	Load	1000	1030	1060	1110	1170	1240	1330	1420
	Cost	19114.9	19594.2	20075.7	20871.8	21834.4	22963.5	24418.8	25910.5
	Network Losses	3.87	4.0	4.12	4.4	4.7	5.1	5.6	6.5
	Spinning Reserve	124.9	124.8	86.1	93.5	84.7	64.7	64.4	68.1
1	P^o	150	150	150	150	150	150	150	150
	ΔP	0	0	0	0	0	0	0	0
	$P^o+\Delta P$	150	150	150	150	150	150	150	150
2		100	100	100	100	100	100	100	100
		0	0	0	0	0	0	0	15.7
		100	100	100	100	100	100	100	115.7
3		56.1	60.8	66.6	76.2	87.7	101.2	118.5	136.0
		2.4	7.72	11.9	12.3	10.8	7.3	0	-7.4
		58.5	68.5	78.5	88.5	98.5	108.5	118.5	128.5
4		354.8	365.4	378.5	400.8	427.3	458.2	498.0	537.9
		2.7	0	11.8	0	0	0	0	0
		352.1	365.4	366.7	400.8	427.3	458.2	498.0	537.9
5		156.97	165.8	176.9	195.4	217.6	243.5	276.8	310
		-5.77	-7.7	0	6.51	9.3	8.4	0.11	-8.3
		151.2	158.1	176.9	201.9	226.9	251.9	276.9	301.9
6		192.1	192.0	191.9	192.1	191.8	191.6	191.4	0
		0		0	-18.9	-20.1	-15.7	-0.111	191.5
		192.1	192.0	191.9	173.2	171.7	175.9	191.5	191.5

Cont'd. on p. 133

Continuation of Table (29) : (DER) of AEP System with Network losses, Spinning Reserve and Security Constraints

Unit Output		Interval 9	10	11	12	13	14	15	16
Load		1505	1590	1670	1750	1820	1885	1945	2000
Cost		27338.7	28775.3	30163.5	31569.3	31569.3	34031.4	35132.5	36066.0
Network Losses		7.3	8.2	9.3	10.6	11.8	12.9	14.0	15.2
Spinning Reserve		60.0	72.9	73.7	75.4	74.6	78.1	72.2	155
1	P^0	150	150	169.6	195.9	238.7	276.64	303.2	303.8
	ΔP	0	13.7	21.2	21.1	2.9	0	0	0
	$P^0+\Delta P$	150	163.7	190.8	217.6	241.6	276.64	303.2	303.8
2		120	132.5	154.6	175.9	210.3	240.8	262.2	262.7
		15.7	23.2	21.1	19.9	5.45	-5.1	-6.5	0
		135.7	155.7	175.7	195.7	215.7	235.7	255.7	262.7
3		145.9	168.7	187.4	200.4	200.0	200.0	200.0	200.0
		-7.4	-20.2	-28.9	-31.5	-21.5	-11.5	-1.5	0
		138.5	148.5	158.5	168.5	178.5	188.5	198.5	200
4		569.9	571.8	570.8	560.1	560.0	560	560	600
		0	0	0	10.7	2.7	0	0	0
		569.9	571.8	570.8	570.8	562.7	560	560	600
5		335.2	380.3	411.1	433.7	437.0	440.4	443.9	450.0
		-8.3	-28.4	-34.2	-31.8	-10.1	0	0	0
		326.9	351.9	376.9	401.9	426.9	440.4	443.9	450.0
6		190.1	193.0	134.7	193.6	185.2	179.7	189.9	198.0
		0	12.6	20.9	11.7	20.4	16.7	8.0	0
		190.1	205.6	205.6	205.3	205.6	196.4	197.9	198.0
CPU Time		= 208.5 Seconds							

CHAPTER 5

CONCLUSIONS AND RECOMMENDATIONS

5.1 SUMMARY

The dynamic economic dispatch with sensitivity analysis for the power system thermal units has been studied. Sensitivity analysis was applied by the use of parametric programming considering variations in the load demand data and the cost coefficient of the objective function. The formulation of the dynamic economic redispatch with sensitivity analysis problem was split into the following:

1- Dynamic Economic redispatch (DER) where load demand (as a deterministic value), units limits and units power rate limits were considered. (No transmission losses)

2- Dynamic economic redispatch incorporating sensitivity analysis for load demand.

3- Dynamic economic redispatch with sensitivity analysis for the cost coefficient of the objective function.

4- Dynamic economic redispatch where the transmission losses were included along with the constraints in item -1.

5- Dynamic economic redispatch where spinning reserve was included along with the constraints in item 4.

6- Dynamic economic redispatch with network losses, spinning reserve, and sensitivity analysis for the load demand.

7- Dynamic economic redispatch with network losses and spinning reserve and sensitivity analysis for the cost coefficient of the objective function.

8- Security constraints dynamic economic redispatch where certain lines were considered to be overloaded (contingency analysis was already performed). The lines flows were expressed in terms of the unit outputs by the use of the generalized generation distribution factors. In this formulation the sensitivity analysis is not considered because our main interest is to secure the system with the available units while meeting the power system constraints. A comparison between table 20 and table 26 shows that the power distribution among the units are different and some excpensive unit have to be loaded more in table 26 than table 20 in order to satisy the constraints.

5.2 CONCLUSIONS

The sensitivity analysis of the dynamic economic dispatch for both the load demand and cost coefficient of the objective function provides us with following advantages (over the dynamic economic dispatch without sensitivity analysis).

1- Sensitivity analysis of the dynamic economic dispatch for the cost coefficient gives us the ability to estimate the changes in the operational cost due to changes in fuel prices and types of fuel. It provides us of how much we are loosing and gaining from one fuel to anothr. As shown in table 8 and 11 the whole range of the cost coefficient, C, for both AEP and CIGRE systems is obtained (for which the solution remains optimum) in about 0.7 seconds only while for each run of the dynamic economic dispatch without sensitivity analysis it takes about

0.52 seconds. This shows the advantage of the sensitivity analysis.

2- The dynamic economic dispatch with sensitivity analysis for the load demand provides us with a valuable information of how much variations that we can have in the load demand over the forecasted values while maintining the same units on line with the cheapest cost. In some intervals an increase of more than 4% in the load demand is not feasible due to the sharp variation of the load curve. The areas between the maximum actual feasible increase and the maximum actual feasible decrease for both AEP and CIGRE Systems provide us with the load uncertainties in the load data that we can have (a sealing margin). The maximum feasible decrease and increase in the load demand was investigated for both systems AEP and CIGRE and the results are shown in figures 7 and 9. In some intervals the load may increase more than 10% without affecting the feasibility of the solution, and in other intervals the 10% increase is not achieved.

5.3 CONTRIBUTION OF THE THESIS

The main contribution of the thesis is problem formulation and solution of the dynamic economic dispatch problem incorporating sensitivity analysis for variations in both load demand and cost coefficient of the objective function. The variation of the load and cost coefficient were studied to determine their effect on the solution.

5.4 RECOMMENDATIONS FOR FUTURE WORK

The following are recommendations for future work for improvemnt:

1. The efficiency of the redispatch technique could be increased if better and faster LP codes were used. A comparison study can be made for the redispatch technique between different types of LP's codes.

2. The matrices of solution techniques are sparse matrices and the solution techniques could be made more efficient in terms of storage requirement (even though power system dispatch centers are equipped with dedicated powerful computers) and execution time.

3. Study the effect of other variations e.g. generator rate limits, spinning reserve parameters etc on the solution.

APPENDICES

APPENDIX - 1

Quadratic Programming

Quadratic programming has been used to fit a function to observations by least square when the coefficients of the function are subject to linear constraints inequalities and the variable in the objective function are nonnegative.

The Beale's quadratic programming method shall be used as mentioned in 3.1 to solve the quadratic part of the problem. It is so now an extension of the simplex method for linear programming which depend on Kuhn-Tucker (K-T) optimality conditions in executing its steps.

The K-T conditions provides the necessary conditions for optimum point. Our problem is a minimization case then the objective function is convex and positive definite since all the constraints are linear. Th constraints definies a convex feasible region of global unique solution.

Using the quadratic programming the following problem is solved.

$$\text{Min} = F = \sum_{i=1}^{NG} F_{i,k}(P_{i,k}) \qquad \text{(A.1.1)}$$

subject to:

$$\sum_{i=1}^{NG} P_{i,k} = P_d^k + P_{losses} \qquad (A.1.2)$$

$i = 1, \text{---} NG$
$k = 1, \text{---} NP$

$$P_i^{min} \leq P_{i,k} \leq P_i^{max} \qquad (A.1.3)$$

$i = 1, \text{---} NG$
$k = 1, \text{---} NP$

The left of the constraint can be eliminated by substituting the following

$$X_{i,k} = P_{i,k} - P_i^{min}$$

in the objective function and in the constraints and the problem will be in the following form and the constant term of the objective function is removed since it does not affect the optimization process.

(3.5)

$$\text{Min: } F = X^t D + X^t C X \qquad (A.1.4)$$

$$\text{Subject to} \quad AX \leq b \qquad (A.1.5)$$

$$X \geq 0 \qquad (A.1.6)$$

Where the matric c is a diagonal matrix whose elements are the quadratic part of the cost function of each unit and the vector D has the linear part of the cost function of each unit. The matrix A contains all the constraints of the problem.

3.2.1 Beales's Method

The problem of (3.4), (3.5) and (3.6) can be stated as follows:

$$\text{Min}: \; F(X) = \sum_{i=1}^{N} d_i X_i + \sum_{i=1}^{N} \sum_{k=1}^{N} X_i Ci_k X_k \qquad \text{(A.1.7)}$$

$$\text{Subject to} \quad \sum_{j=1}^{M} a_{ij} X_j \, Y_i = b_i \qquad \text{(A.1.8)}$$

$$j = i, \text{---} M$$
$$i = 1, \text{---} N$$

$$X_i, Y_i \geq i \qquad \text{(A.1.9))}$$

The method starts with an initial feasible solution which specifies the basic and nonbasic variables. The Y-variables are basic and the X-variables are non basic. The constraints are then written as follows [9]:

$$Y_i = b_i \sum_{j=1}^{N} a_{ij} X_j \qquad \text{(A.1.10)}$$

The objective function is given in terms of the nonbasic variables, equation (3.7). In each iteration the objective function is improved by choosing a new bsic variable and a leaving variable, after which the objective function and the constraints are modified accordingly. If for example, X_i is the new basic variable, and Y_i is the leaving, then the corresponding jth constraint which is

$$Y_j = b_j - a_{i1}X_1 - aj_2\, X_2 \ldots\ldots a_{jn}X_n \qquad \text{(A.1.11)}$$

is written as

$$X_i = (b_i/a_{ji}) - (Ya_{ji})Y_i - (a_{j2}/a_{j1})\, X_2 \ldots\ - (a_{jn}/a_{ji})\, X_n \qquad \text{(A.1.12)}$$

and this expression is to eliminate X_i from the objective function and the constraints. the transformation for the constraints is similar to the simplex transformation with a pivot element in ordinary linear programming.

For the objective function, the transformation is more complicated, but it is clear that a new objective function in the nonbasic variables is obtained. In [19] it is shown that transformation of contraints and objective function is performed by two successive simplex operations. A new basic variable is selecxted based on the partial derivatives of the objective function with respect to the non-basic variables. In the initial tablean, these deviations are

$$\frac{\partial F}{\partial X} = D + 2CX \qquad \text{(A.1.13)}$$

Since the X-variables are nonbasic, the term CX cancels. If an element of D is negative, an increase in the value of the corresponding X-variables will decrease the value of the objective function. Hence, the nonbasic variables having the smallest negative coefficient in the linear part of the objective function is choosen to enter the basic [9] It this variable is X_j then the corresponding equation is

$$\frac{\partial F}{\partial X} = d_i + 2C_{ij} X_j + 2C_{jj} X_j + 2C_{nj} X_n \qquad \text{(A.1.14)}$$

and this derivative stays negative unitl

$$X_i = |d_i| \; 2C_{jj} \qquad \text{(A.1.15)}$$

beyond which the objective function starts to increase.

On the hand, the current basic variables should remain nonnegative, therefore X_j can be increased until one of the basic variable becomes zero. This happens when X_j asssumes the value

$$\text{Min} \{ b_i/a_{ij} / \alpha_{ij} > 0 \} \qquad \text{(A.1.16)}$$

The "free-variable" means it is not sign restricted (may taken positive or negative value) and if it occurs at a later iteration wth a nonzero linar part in the objective function, it can be decreased when it has a positive partial derivative, causing the objective function to decrease. It can be increased with it has a negative partial derivative, again decreasing the objective function. Beal denoted the tableau having a nonbasic free variable with nonzero partial derivative as a nonstandard tablau. In any nonstandard tableau, the fre variables should enter the basis before any sign restricted variable and therefor restoring standard tableau.

The algorithm finds the optimal solution when no entering variable can be found to decrease the objective function, that is when the partial derivatives of the objective function with respect to the nonnegative and with respect to the nonbasic unrestricted variables are all zero.

The smaller value of (3.15) and (3.16) is choosen. If smaller value is in (3.16) the correspinding variable leaves the basis. If the smaller value occurs in (3.15) then a new Z_l called a "free-variable" is introduced into the nonbasic set as a contro, over the derivative. This variable is given as

$$Z_l = \partial F/\partial X_j \qquad \text{(A.1.17)}$$

Hence, it can be considered as a basic variable in Equation (3.7). We therefore, have added a new variable and a new constraint to the poroblem and we use equation (3.14) to eliminate X_i from the constraints and the objective function as follows:

$$X_j = -(d_j/2C_{jj}) - (C_{ij}/C_{jj})\,X_1 \text{ -------- } + (C_1/2C_{jj})Z_1 \text{ ----}$$

$$-((C_n)\,/\,C_{jj})\,X_n \qquad \text{(A.1.18)}$$

The algorithm set-ups are shown in the flow chart in Figure No. 2. The initial A and F- tableaus are shown in Table .1

TABLE (30). Initial A - and F - Tableau of Beale's Method

		Value	Non-basic variables	
Nonbasic variables	X	0	I_{NXN}	A-tableau
Basic variables	Y	B		
Nonbasic variables	X	D	C	F-tableau

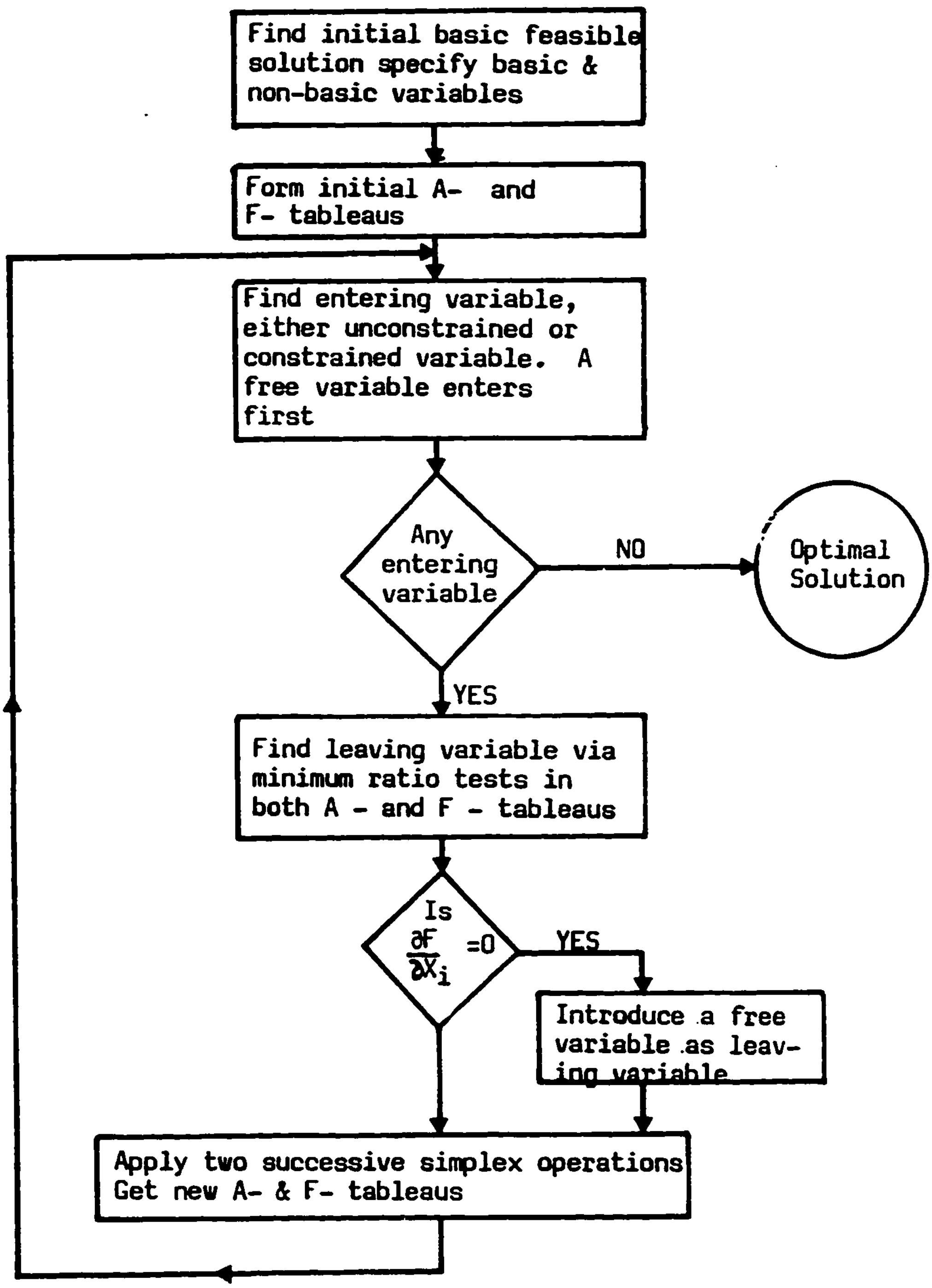


Figure 10: Flowchart of Beale's Method

APPENDIX - 2

Linear Programming Method

Linear programming simply seems to find th optimum value of a linear objective function while meeting a set of linear constraints. There are a variety of solution to the LP problem. The LP technique presented here is called Simplex upper bounding dual linear programming algorithm. The dual-upper bounding algorithm proceeds in simple steps where in variables that are in the basis are exchanged for variables out of the basis. When an exchange is made, a pivot operation is carried out at the appropriate row and column. The nonbasis varaibles are held equal to either their uper or their lower value while the basis variables are allowed to take any value without respect to their upper or lower bounds. The solution terminates when all the basis variables are within their respective limits.

The following problem is solved by the linear programming.

Min:

$$F = \sum_{k=1}^{NP} \sum_{i=1}^{NG} (b_i + 2C_i P^o_{i,k}) \Delta P_{i,k} \qquad \text{(A.2.1)}$$

$i = 1, \text{---} NG$
$k = 1, \text{---} NP$

subject to

1- Power demand equation:

$$\sum_{i=1}^{NG} \Delta P_{i,k} = 0 \tag{A.2.2}$$

2- Units Operating Limits:

$$P^{o}_{i,k} - P^{min}_{i,k} \leq \Delta P_{i,k} \leq P^{max}_{i,k} - P^{o}_{i,k} \tag{A.2.3}$$

3- Power Rate Limits:

$$-\Delta P_{i,k} + \Delta P_{i,k+1} \leq RU_i + P^{o}_{i,k} - P^{o}_{i,k+1} \tag{A.2.4}$$

$i = 1, \text{---} NG$
$k = 1, \text{---} NP$

4- Spinning reserve Requirements:

4.1

$$\Delta P_{i,k} - \Delta W_{i,k} \leq RU_i + P^{o}_{i,k} + W^{o}_{i,k} - P^{max}_{i,k} \tag{A.2.5}$$

4.2

$$\Delta P_{i,k+1} - \Delta P_{i,k} - \Delta \eta_{i,k} \leq P^{o}_{i,k} + \eta^{o}_{i,k} - P^{o}_{i,k+1} \tag{A.2.6}$$

$i - 1, \text{---} NG$
$k = 1, \text{---} NP$

4.3

$$\sum_{i=1}^{NG} (-2\Delta P_{i,k} + \Delta P_{i,k+1} - \Delta W_{i,k} - \eta_{i,k}) \geq SR\,(k) + \Delta P_d^k +$$

$$\sum_{i=1}^{NG} 2P^o_{i,k} + W^o_{i,k} + \eta^o_{i,k} - P^o_{i,k+1} - P_i^{max} \qquad \text{(A.2.7)}$$

5- Security Constraints:

$$\sum_{i=1}^{NG} D_{\ell-m,i} \, \Delta P_{i,k} \leq f^j_{\ell-m} - \sum_{i=1}^{NG} D_{\ell-m,i} \, P^o_i \qquad \text{(A.2.8)}$$

$i = 1, \text{---} NG$
$k = 1, \text{---} NL$

The following flowchart shows the redispatch steps i.e. the QP and the LP togather.

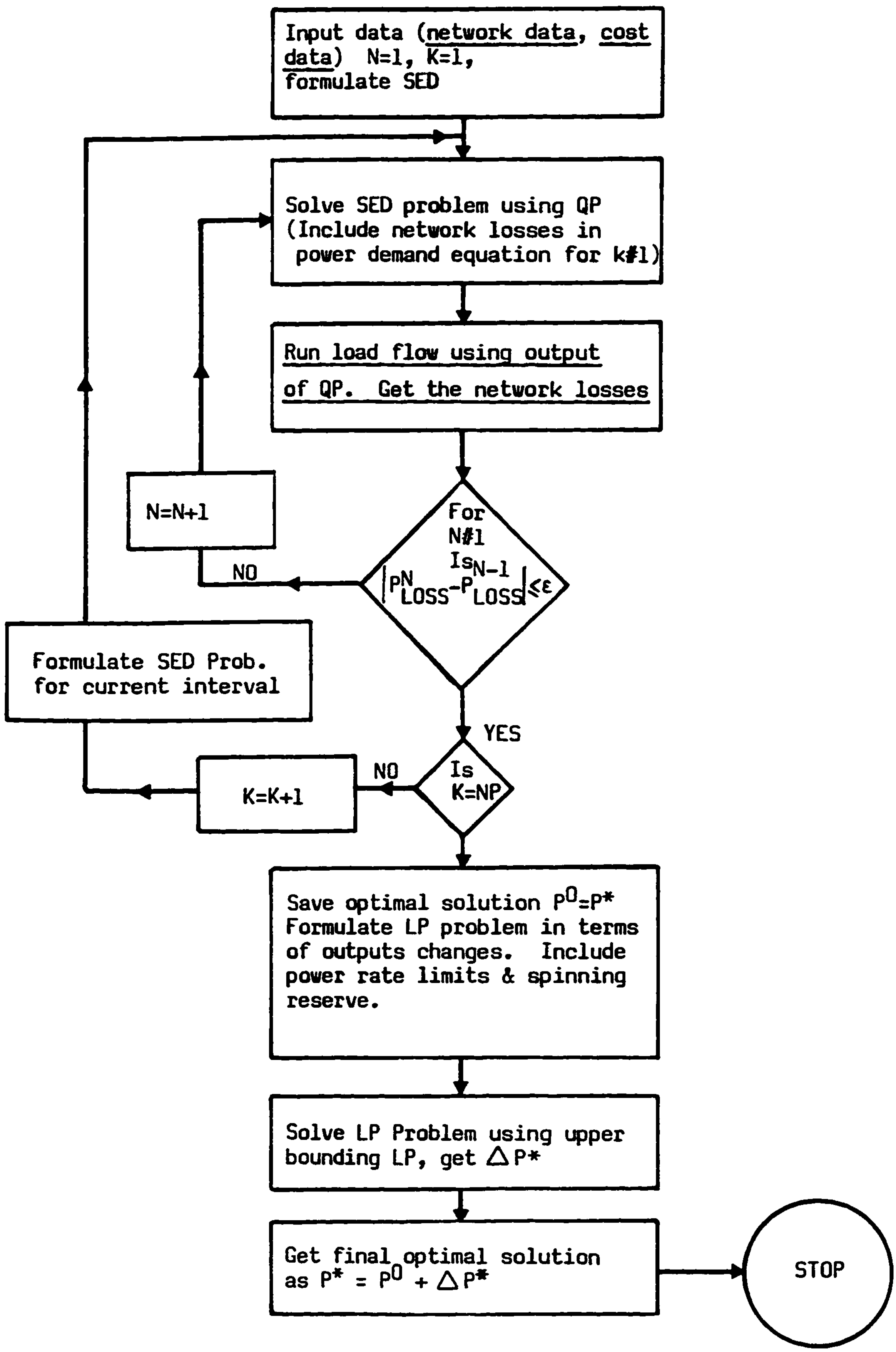


Figure 11: LP Technique

APPENDIX 3

TABLE (31) Network Data of AEP System.

Line #	S bus	E bus	R(p.u.)	X(p.u.)	Line charging Y/2 p.u.	Tap
1	1	2	0.0017	0.0294	0.0412	1.0
2	1	11	0.0045	0.0185	0.1020	1.0
3	2	8	0.0104	0.1360	0.0287	1.0
4	4	8	0.0001	0.0486	0.0138	1.0
5	2	4	0.0003	0.1989	0.0208	.
6	2	13	0.0106	0.1380	0.0292	.
7	8	13	0.0012	0.0041	0.0225	.
8	4	7	0.002	0.1486	0.0326	.
9	13	7	0.0027	0.0082	0.0425	.
10	13	5	0.0033	0.0419	0.0047	.
11	13	9	0.0	0.0208	0.0	1.022
12	13	10	0.0	0.0556	0.0	1.032
13	9	3	0.0	0.1294	0.0	
14	9	10	0.0	0.0110	0.0	
15	8	12	0.0	0.0256	0.0	1.073
16	12	6	0.0	0.0467	0.0	
17	12	14	0.0123	0.0256	0.0	
18	12	15	0.0066	0.0130	0.0	
19	12	16	0.0094	0.0199	0.0	
20	14	15	0.0221	0.02	0.0	

Cont'd Table (31)

Line #	S bus	E bus	R(p.u.)	X(p.u.)	Line charging Y/2 p.u.	Tap
21	16	17	0.0082	0.0193	0.0	1.0
22	15	18	0.0107	0.0219	0.0	1.0
23	18	19	0.0064	0.0129	0.0	1.0
24	19	20	0.0034	0.0068	0.0	1.0
25	10	20	0.0094	0.0209	0.0	.
26	10	17	0.0032	0.0085	0.0	.
27	10	21	0.0035	0.0075	0.0	.
28	10	22	0.0073	0.0150	0.0	.
29	21	22	0.0012	0.0024	0.0	.
30	15	23	0.010	0.0202	0.0	.
31	22	24	0.0115	0.0	0.0	.
32	23	43	0.0132	0.0270	0.0	.
33	24	25	0.0188	0.0329	0.0	.
34	25	26	0.0254	0.0380	0.0	1.0
35	25	27	0.0109	0.0209	0.0	.
36	28	27	0.0	0.0396	0.0	1.033
37	27	29	0.0220	0.0415	0.0	
38	27	30	0.0320	0.0603	0.0	1.0
39	29	30	0.0240	0.0453	0.0	1.0
40	5	28	0.0177	0.1996	0.0224	1.0
41	13	28	0.0017	0.0060	0.0325	1.0

TABLE (32) Network Data of CIGRE System

Line #	S bus	E bus	R(p.u.)	X(p.u.)	Line charging Y/2 p.u.
1	5	6	0.0357	0.8145	0.0191
2	9	6	0.0216	0.3512	0.044
3	6	7	0.0225	0.4954	0.066
4	3	6	0.0856	0.7855	0.044
5	5	7	0.0021	0.0479	0.05063
6	9	7	0.0055	0.0358	0.2329
7	4	7	0.0008	0.0091	0.1164
8	1	7	0.0008	0.0196	0.10125
9	10	7	0.0018	0.0122	0.3493
10	8	9	0.0488	0.1916	0.10125
11	8	4	0.0183	0.0628	0.10125
12	8	2	0.0118	0.0786	0.15188
13	10	3	0.0163	0.0638	0.15188

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